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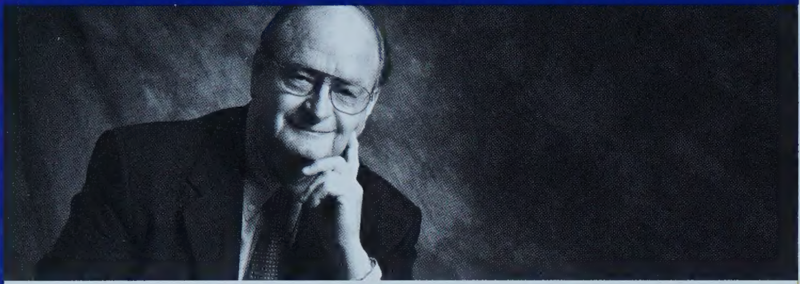
EPCOR Annual Report **2** thousand and **3**

2003

Message from the Chairman



This was a remarkable year to be a member of the EPCOR Board.

We have long held that good corporate governance is essential to a principled, well-run and sustainable business. It is particularly important for EPCOR, because the independence and transparency of our governance model provides our public-sector Shareholder an investment with the discipline and competitiveness of a widely-traded company.

We were honoured to have our governance model nationally recognized as a model for both public and private sectors. As you can read in this report, EPCOR was named both the sector winner and overall winner of the National Awards in Governance, presented by the Conference Board of Canada and Spencer Stuart.

Described by the panel of adjudicators as "a governance system worthy of the very best publicly traded companies," the citation recognized the Board's capacity to make strategic business decisions, EPCOR's voluntary and full compliance with the Toronto Stock Exchange's (TSX) corporate governance guidelines, and our model for the recruitment and evaluation of Directors.

Our Directors are respected business and community leaders from Vancouver, Calgary, Edmonton and Toronto. Each Director brings a unique viewpoint, relevant experience and their personal commitment to the table. In 2003, we were pleased to welcome to our Board Steven Matyas, President of The Business Depot Ltd.

The National Award in Governance is especially meaningful at a time when practices are under increasing scrutiny, regulation and reform.

I am pleased to report that EPCOR's implementation of best practices in governance preceded recent market controversies. The Board promptly and voluntarily implemented the guidelines put forth by the Dey and Saucier reports, and later the TSX.

We continue to pursue practices that will enhance our governance system. For 2004, we will report our compliance with the eighteen new governance guidelines set out by the Ontario Securities Commission.

The governance system has allowed EPCOR to capitalize on growth opportunities, and navigate forward through challenging market conditions. It has worked because we have a courageous Shareholder, Directors with the right mix of experience and know-how, and a first rate management team that remains tightly focused on running the business.

On behalf of the Board, I must express appreciation to the Shareholder for their continued support of our work. Our Board is also fortunate to work with a management and employee team that is one-of-a-kind, truly skilled and exceedingly dedicated. Finally, I would be remiss if I did not acknowledge the contributions of my colleagues on the Board, who are tremendous leaders in their own right. I am sincerely grateful for the consistent effort they have put into making EPCOR a world-class company.

Hugh J. Bolton
Chairman of the Board

Message from the President

In 2001, my annual message was that EPCOR is in a race to be the best – and that the race was a marathon, not a 100-metre dash. Success requires patience and perseverance. The past three years have brought that point home.

In that time, leading energy companies have closed their doors, investors have lost value, and there have been nearly 300 credit downgrades in the North American utility sector. Deregulation, while advanced in Alberta, has lost momentum elsewhere. Competitive generation – a bright spot in 2001 – is in a down cycle: reserve margins discourage investment in most markets, and are accompanied by natural gas prices that threaten the value of existing merchant generation.

The market has tested EPCOR's people, processes and resourcefulness. Measured against these tests, the company has continued to deliver value to customers, investors and communities. In 2003, we strengthened our balance sheet, maintained an investment-grade credit rating and raised our common dividend.

EPCOR's business strategy remains unchanged: to balance regulated and unregulated assets within an integrated energy company. Our financial results reflect that strategy, with steady performance from the regulated base backstopping the cyclical returns of our competitive businesses.

Throughout the year, we continued to strengthen our core interests in regulated water services, electricity distribution, and the development and operation of additional generation assets. The most significant of these is our construction of the Genesee Phase 3 project (GP3). Its progress continues to be a remarkable success story. Thanks to Hitachi Canada, Colt Engineering and a team of over 2,000 contractors and employees working around the clock, GP3 is on time, on budget, and one of the safest industrial construction sites in the province.

The same high level of performance continues to be demonstrated in the operation of EPCOR's water plants, distribution networks, and generation assets. Because of the dedication of our staff, EPCOR delivers power and water to customers while consistently achieving superior reliability, quality and safety ratings.

EPCOR's customer service teams also made a real difference in 2003. Service is faster and better, and customers tell us they're more satisfied than they were a year ago. Work took place behind the scenes to improve back office functions, where teams made progress in identifying and repairing the root causes of billing problems that had frustrated both us and our customers. By the fourth quarter their efforts were reflected in both our operating and financial performance. There is still work to be done, and we will not rest until our customers and people tell us the job is done.

We took a number of steps in 2003 to sharpen our business focus, strengthen the balance sheet and reduce risk exposure.

EPCOR entered into partnerships with TransAlta Corporation and Puget Sound Energy on two of our principal competitive generation investments. We also made the decision to exit the competitive residential mass-market for electricity and natural gas, and having done that, unlocked the value of our investments through divestiture and a successful Initial Public Offering of our Ontario-based Union Energy business.

With a strong balance sheet, and an investment-grade credit rating, the challenge now is to find investments that are accretive to cash flow. It is more important to make the right decision than to make a hasty decision. But with confidence in our business strategy and our team, we are prepared to find the right opportunity, and move decisively when it appears.

None of this would be possible without our people – some of the best and brightest in any industry – or without best-in-class governance. Looking ahead, these will be our foundation as we continue to build our reputation, grow in new markets, and meet the challenge of making each technology, project and investment better than the last.

I look forward to reporting on those achievements.

Don Lowry

Donald J. Lowry
President and Chief Executive Officer

Blazing a trail for cleaner coal generation

Safety first. Dave Hill, who leads EPCOR's corporate safety programs; and the Genesee Phase 3 construction site, which reached a milestone one million work hours without a lost-time injury in 2003.

PERFORMANCE

Safety in Numbers

Performance

In 2003, EPCOR moved ahead with new ideas, anticipation and purpose.

The company exited the mass retail market, choosing to focus its competitive energy business on large-scale customers and power generation opportunities. Much of this work was concentrated in Alberta, Ontario, British Columbia and the U.S. Pacific North West.

On its regulated side, EPCOR supported the critical infrastructure of several Western Canadian municipalities. One million people had clean, safe water to drink. Electricity flowed from generators to homes, businesses, hospitals and schools without incident or major interruption.

EPCOR built its business more than 100 years ago based on the principles of safety and reliability. Statistics today tell the same story.

The company's coal and natural gas-fired power plants consistently rank among the top generators in Canada. In 2003, the Canadian Electrical Association ranked EPCOR's Genesee Unit 2 performance in 2002 as the best in the country among thermal units for both availability and operating reliability.

Availability means how often the plant was available to supply needed power, while operating reliability measures how often it was shut down for repairs. Genesee Unit 1 also ranked in the top 10 in Canada in both categories.

To renew Alberta's electricity supply, EPCOR is building Genesee Phase 3 (GP3), a 450 MW plant, in partnership with TransAlta Corporation. With GP3, EPCOR has made an industry leading commitment to reduce CO_2 emissions to the equivalent of a combined cycle natural gas plant.

The plant underscores EPCOR's emphasis on safety and reliability. As one example, its 500 kV circuit breaker will provide the fastest protection against line faults in the industry when complete. This is another way EPCOR works to deliver on the commitment that each project will be better than the last.

Rising from the prairie skyline west of Edmonton is the skeleton of a 73-metre steel structure. It towers over one of the largest and busiest construction sites in Alberta, employing 42 different contractors and over 2,000 workers, belonging to 16 unions.

Housed inside is a supercritical boiler and inner workings that will make the plant, Genesee Phase 3 (GP3), Canada's most technologically advanced coal-fired power plant. Hitachi Canada Ltd. is playing a leading role in the design of the boiler, and a high-efficiency, multi-stage turbine generator.

Environmental performance aside, GP3 was thrust into the spotlight in 2003 for an entirely different reason. Halfway through the year, the project marked one million work hours without a lost-time injury. Not only was GP3 on time and on budget, but it also had one of the province's best safety records.

As of year-end, the GP3 project had recorded a lost-time claim rate of 0.14 per 100 person-years worked, more than 25 times better than the province's industrial construction sub-sector lost-time claim rate of 3.7.

This was no small feat given the technical and logistical challenges GP3 posed. Using a unique modular approach to construction, trades people worked on site at the same time instead of in phases, assembling piping and ductwork as the steel structure was built. Entire floors were constructed at ground level, and then lifted and bolted into columns that stood in place.

The plant's components include the 256-tonne turbine generator, a 135-metre stack, switchyards, a highly efficient fabric filter and electrical distribution systems. About 4 million kilograms of steel were needed for the structure, and 311 kilometres of pressure piping for the supercritical boiler.

Logistically speaking, upwards of 1,000 workers were on site at one time, alternating in two shifts. GP3 construction is on a fast track. The plant will be operational just three years after receiving regulatory approval.

GP3 is blazing a trail for cleaner coal generation. Looking ahead, it will also renew Alberta's electricity supply by bringing 450 MW of additional power on-line – enough to meet the electricity demands of a quarter of a million people. The journey to GP3's completion has been innovative. It has been focused. Above all, it has been safe.

Making communities better. **Gyn-Gyn Lee** managed the installation of ultraviolet water treatment technology in Canmore and at Edmonton's Rossdale Treatment Plant. To celebrate the City of Edmonton's 100th birthday, EPCOR is building a dynamic waterfall in the downtown core.

Building for the Future

PARTNERSHIPS

Partnerships

EPCOR's water business celebrated a 100-year birthday in 2003. It has grown from serving a small turn-of-the-century city to providing water and wastewater services to one million people in 50 communities across Western Canada.

During the year, EPCOR continued to form partnerships with municipalities and industry to help improve water quality and address aging infrastructure. It was selected as the preferred partner in the proposed construction of a $23 million wastewater system for the District of Sooke on Vancouver Island.

The Greater Vancouver Regional District sought EPCOR's expertise in the design of its Seymour-Capilano Filtration Plant — one of the largest water treatment facilities under construction in North America.

New York City invited EPCOR to join a technical committee overseeing the installation of ultraviolet (UV) technology into its massive water treatment system. Each day, the system handles eight billion litres of water, cleaning and purifying it for a population one-third the size of Canada.

UV disinfection provides 100 times the current safety factor for cryptosporidia and other waterborne parasites. In 2003, EPCOR began work on installing nine UV units at its Rossdale Water Treatment Plant in Edmonton. Upon completion in 2005, a total of 129 billion litres of water, provided annually to residents of Alberta's capital region, will be protected by UV filtration.

The year also marked a successful entry into the industrial market, as EPCOR won contracts for water and wastewater services with the Suncor and Albian Sands oil sands projects north of Fort McMurray, Alberta.

EPCOR has consistently demonstrated leadership in setting high standards for its water and wastewater operations. This will serve the company well, as a renewed focus is placed on the need for an adequate supply of water – and protection of its source – for the future.

Problems occur when demand outstrips supply, particularly when dealing with essentials such as water and power. The energy crisis that gripped California and the U.S. Pacific North West in 2001 offers a case in point. In this situation, EPCOR responded with Frederickson Power, one of the first generators to come on-line in Washington State in the wake of the crisis.

Commissioned in August 2002, Frederickson brought 249 MW of much needed power to the regional grid. It assured the Benton, Franklin and Grays Harbor Public Utility Districts a secure power source for 20 years.

Sprawling new neighbourhoods on a city's outskirts are a sure sign of strong economic times. Passing by, most people are struck by the distinctive homes that line the landscape, and they're curious about the next stage of development.

Few look deeper than the surface. What's underneath is an extensive network of power cables and pipelines that deliver the essentials – electricity and water. In Edmonton, these are tools of EPCOR's trade.

Considerable technical attention and detail is put into the infrastructure that supports one of Canada's fastest growing cities. The Edmonton metro area was home to one million people in 2003.

In the last year alone, 50 kilometers of water main and almost 300 hydrants were installed to extend Edmonton's water distribution system to over 4,400 new residential lots. Compared to figures from 2000, this was an 86% increase in the number of new lots serviced.

On the power side, EPCOR engineers ensured that any connection to the electrical distribution system was a safe one. Plans were reviewed. Construction work was closely inspected time and again. New lots were energized. In total, 9,000 new power meters were installed to support new homes and businesses.

There can be no compromise when it comes to maintaining the integrity of an intricate network, with its vast array of poles, lines, cables, vaults and transformers.

People expect the lights to turn on. They expect to have safe, clean drinking water. For 100 years, EPCOR has had a solid record of performance in providing utility services. That tradition is well intact today.

Finding new solutions in a changing marketplace

Client-driven products and services. Joe Gysel leads EPCOR's competitive energy and marketing activities in Alberta, Ontario, British Columbia and the U.S. Pacific North West. Three 24-hour real-time trading desks optimize energy load management.

Getting to the Bottom Line

INNOVATION

Innovation

Customized solutions backed by a tested team of technical, financial and analytical experts. This has been a drawing card for large consumers buying power and natural gas in a competitive marketplace. And, EPCOR's got the client list to prove it.

More than two million customers depend on energy provided through EPCOR. A leader in deregulated energy markets, EPCOR operates in Alberta, Ontario and the U.S. Pacific North West. It transacted 3,500 MW of power and 91,000 bcf of natural gas in 2003, and managed 2,000 MW of generation assets.

Clients such as The Boeing Company and Air Liquide, a world leader in industrial and medical gases, called on EPCOR to help manage their energy needs. Over 700 new mid-commercial clients were signed during the year.

One of only three energy companies to receive Electricity Service Supplier certification with Portland General Electric (PGE), EPCOR became an option for PGE customers seeking a competitive power supplier.

EPCOR offers a full suite of energy products, and the benefits that come with operating three 24-hour real-time trading desks to optimize load management. To stay on top of the game, the company evaluated its entire product line and services in 2003 to meet changing market demands.

As a result, customers were given more options to manage risk and control operating costs. These covered the spectrum, from physical to financial contracts in customized hourly, daily or term lengths to optimize their portfolio. An innovative Web portal was also developed, allowing select customers 24-hour access to detailed breakdowns on load, consumption and bill data.

In Ontario, EPCOR introduced a billing system that allowed customers to receive one electricity bill instead of two. They were also able to view the details of their energy transactions, and separate their aggregate energy charges on a site-specific basis.

In Alberta, through EPCOR's EnVest program, commercial and industrial customers continued to access resources that allowed them to make major energy improvements to their water, gas and electric systems.

EnVest allowed customers to save money, increase their energy efficiency and reduce emissions. In 2003, over 90 customer sites optimized their operations, reducing consumption by 14,925,000 kWh. This was the equivalent to removing 7,464 cars from the roads or heating 1,990 homes.

Cutting out costs. Creating efficiencies. Buzz words in the world of business. But, when a company's workforce takes them seriously, things start to happen.

EPCOR employees chose to do just that in 2003. With the mindset that pennies saved can amount to dollars, they squeezed out excess operational costs. The goal was to create a more efficient company, capable of delivering the most competitive products and services to customers.

Fifty-five EPCOR employees put corporate purchasing and supply processes under a microscope. Representing business units across the company, they were grouped in nine teams. One team had the daunting task of reviewing purchases of 3,400 electrical items from tiny components to huge transformers.

Another team analyzed printing needs and spending across business units. It then called for tenders in four main areas, later negotiating new cross-company contracts. As a result, EPCOR is expected to spend 30% less on printing in the year ahead.

A third team introduced a purchasing card – complete with stringent checks and balances – to cut down the cost of processing invoices and petty cash transactions, and expedite payment to suppliers. Six hundred eligible employees signed up for the card, recording about 3,000 transactions a month. This reduced the overall number of purchase orders by one-third by year-end.

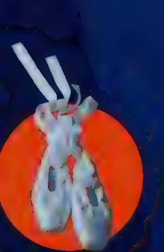
Down the road, this company-wide approach is expected to yield overall savings in the millions and boost buying power. It has already streamlined a number of internal processes.

There's another important byproduct. EPCOR employees are building a culture of co-operation, one that promotes the sharing of best practices and puts value for the customer first.

Leaping into action: Dianne Allen, who leads EPCOR's nationally recognized community partnerships, is shown with Alberta Ballet dancer Hokuto Kodama.

CITIZENSHIP

An Inspiring Performance



Citizenship

Citizenship comes with both rights and responsibilities. In EPCOR's case, it carries an added dimension — a desire not only to sustain communities, but also to rejuvenate them.

EPCOR's record of community involvement is extensive, with contributions to areas such as the arts, health, education and the environment. In 2003, the company focused attention on helping and educating people. Its efforts to maintain a healthy and productive workforce were recognized for a fourth straight year, as EPCOR was again named one of Canada's Top 100 Employers.

During the summer, EPCOR launched a fundraising campaign to support the Alberta beef industry as it coped with the mad cow crisis. President & CEO Don Lowry hosted a backyard barbecue in downtown Edmonton, serving up more than 1,000 burgers to lunch goers for a $2 donation. EPCOR staff also pitched in, buying 32,401 lbs of beef valued at $70,000.

It's said that laughter is the best medicine. EPCOR set out to prove just that for the fourth year running with its sponsorship of Comedy Cares. The program brought performers to hospitals and health care facilities in communities such as Stony Plain, Canmore and Strathmore, Alberta, where EPCOR operates.

EPCOR rolled out its Electricity Smarts campaign in 2003 to create greater awareness around the hazards that electricity can pose. The advertising campaign targeted adults and youth, complementing its existing school programs.

The definition of a good corporate citizen goes well beyond the borders of a community. It is rooted in good governance and ethical business practices. Companies are judged by how well these translate into action.

With a climate change strategy in place since the mid-1990s, the company has invested time and energy to finding ways to reduce impact on the environment. Today, EPCOR is a leader on a number of fronts, as a provider and generator of Green Power, by applying new technology to reduce emissions, and supporting research for the future.

In the future, more electricity will be generated from alternate energy forms. Sources such as wind, solar and small hydro will complement thermal generation in the foreseeable future.

EPCOR is convinced there is potential in the wind. In 2003, the company sought to expand its wind generation portfolio, actively pursing opportunities in both Canada and the U.S..

EPCOR's third "run-of-river" hydro facility neared completion. When final commissioning is complete in 2004, the Miller Creek hydro plant in British Columbia will generate 110,000 MW hours of electricity annually, the equivalent of removing more than 641,000 cars off the road each year.

In Alberta, EPCOR worked closely with industry, government and environmental stakeholders through the Clean Air Strategic Alliance to reach a concensus on principles that will guide air emissions management for the electricity sector. The principles secure affordable long-term air quality improvements, while providing greater certainty for generation investors and operators.

Nothing inspires more than the energy of a fine performance.

In 2003, EPCOR took center stage, demonstrating a unique commitment to Calgary's arts community. It was a performance that earned national acclaim.

EPCOR captured top honours for Best Arts-Entrepreneurial Partnership in the 25th annual Business in the Arts Award, presented by the Council for Business in the Arts in Canada and the National Post. A spotlight was cast on the company's affiliation with the EPCOR Centre for the Performing Arts.

Moving in perfect sync, the partners worked a theme of sustainability into the overall production piece – ensuring the Centre will remain a cultural cornerstone in Western Canada, capable of drawing world-class performers for years to come. The theme expressed a passion for the arts, and its intrinsic value to the life of people and communities.

EPCOR's commitment to the Centre spans 10 years. It has involved the creation of an endowment fund, and at an operational level, EPCOR helped the Centre convert its six-level, 400,000-square-foot facility into a model of energy efficiency in the use of electricity, natural gas and water.

As the performance unfolded during the year, its players proved that business can work in harmony with the arts. And, after a triumphant first appearance, they stand ready for a curtain call.

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A green light for innovation. Dr. Michael Percy, Chair of the Corporate Governance and Nominating Committee of EPCOR's award-winning Board of Directors, and EPCOR's energy efficient LED traffic signals.

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Value

EPCOR has stayed competitive and brought increasing value to its Shareholder, even during some of the most challenging times for the utility industry. The company's response to changing market conditions in 2003 was always quick, always thoughtful.

In August, EPCOR announced it would exit the competitive mass retail market, choosing to halt natural gas and electricity contract sales to residential, farm and small commercial customers. EPCOR was one of Canada's most successful competitive retailers, with more than 200,000 Ontario customers and another 95,000 in Alberta. But with few jurisdictions in Canada and the U.S. opening up for business, and continued market uncertainty, the growth potential of this segment had diminished considerably.

The company retains 600,000 Alberta electricity customers under a regulated rate option, and remains committed to meeting their expectations for quality service. EPCOR's Call Centre, which responded to more than one million customers in 2003, greatly improved its service. On average, customers received personal attention to their questions and concerns in under a minute. Efforts to improve service remained a priority for the company. This was recognized during the year, as EPCOR President & CEO Don Lowry was named the Consumers' Choice Award Businessman of the Year for Edmonton.

The August decision led to the divestiture of Union Energy, an EPCOR subsidiary in Ontario, which owns water heater rental; heating, ventilation and air conditioning; and consumer finance businesses. By December, Union Energy had been sold to a newly formed income fund through an initial public unit offering. The net proceeds of the sale were $793.3 million, resulting in a gain of $291.1 million and strengthening of the company's balance sheet.

EPCOR's performance was further reinforced by a continued focus on risk management strategy. The company made a concerted effort to reduce risk, always balancing risk against a realistic appraisal of likely market outlook and returns.

EPCOR opted to share risk on two major power generation projects. It signed an agreement with Puget Sound Energy to partner on its 249 MW Frederickson Power natural gas facility in Washington State. The agreement is subject to regulatory approval and is expected to close in 2004. Earlier in the year, EPCOR sold a 50%, or 225 MW, interest in its state-of-the art Genesee Phase 3 coal-fired plant to TransAlta Corporation.

EPCOR also looked to create new competitive advantages through strategic venture capital investments. This included a $1.5 million investment in RuggedCom Inc., which develops and manufactures utility-hardened networking technology that operates reliably under extreme physical conditions.

Corporate governance has moved out of the boardroom into plain public view. How a company is run, its ethics and oversight practices weigh heavily on the minds of both shareholders and consumers.

As boards and their directors come under increasing scrutiny, regulation and reform, EPCOR has set a new standard for excellence in corporate governance.

The Conference Board of Canada and Spencer Stuart recognized EPCOR with their National Award in Governance. A panel of judges noted that EPCOR has a governance model in place worthy of the best publicly traded companies. Municipally owned, EPCOR operates a growing and complex business that is active in Alberta, British Columbia, Ontario and the U.S.

Its Board of Directors has authority to make strategic business decisions. Members of the Board are business leaders from Vancouver, Calgary, Edmonton and Toronto. They are selected because they have the experience and know-how needed to move the company forward.

Under their watchful eye, EPCOR has enhanced Shareholder return, increasing its common dividend by 50% since 1998.

These are the hallmarks of a governance model that has delivered on its potential. EPCOR has long believed it had merit. Now, with national recognition in hand, it's clear others are in agreement.

Report on Governance

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Summary of Corporate Governance Practices

The Toronto Stock Exchange (the "TSX") requires that companies listed on that exchange disclose their corporate governance practices as compared to corporate governance guidelines recommended by the TSX. EPCOR Utilities Inc. ("EPCOR") is not a listed company on the TSX, however the company has chosen to voluntarily disclose its compliance with the guidelines as of December 31, 2003. The following table summarizes and provides comments on EPCOR's voluntary compliance.

TSX Guideline	Does EPCOR Comply?	Comments
1) The Board of Directors (the "Board") should explicitly assume responsibility for stewardship of the corporation and specifically for:	Yes	EPCOR's directors (the "Directors") are responsible for stewardship of the corporation. All of the outstanding shares of EPCOR are owned by the City of Edmonton (the "Shareholder"), and some of the Directors' powers are limited pursuant to a unanimous shareholder agreement.
a) Adoption of a strategic planning process;	Yes	The Board holds an annual strategic planning session, and reviews and approves the corporation's Long-Term Plan. In addition, the Board sets aside one meeting with EPCOR's Shareholder each year to report on the strategic plan and respond to questions.
b) Identification of principal risks to the corporation's business and the implementation of appropriate systems to manage such risks;	Yes	Management is responsible for the identification of EPCOR's principal risks, and the assessment and mitigation of these risks. The Audit Committee monitors financial risks and the Board has oversight responsibility for all business risks faced by the company. Commodity risk management is a standing agenda item at all Board meetings.
c) Succession planning, including the appointment, training and monitoring of senior management;	Yes	The Board has responsibility to ensure succession planning, training and monitoring of senior management. The Board has delegated that responsibility to the Human Resources and Compensation Committee which reports annually to the Board.
d) A communications policy;	Yes	A formal communications program is in place and requires the timely disclosure of material information relating to business activities and corporate performance to the public and to the Shareholder.
e) Integrity of the corporation's internal control and management information systems.	Yes	The Audit Committee has oversight responsibility to ensure that management has implemented adequate internal control and management information systems. The Audit Committee reports on its activities at each meeting of the Board.

TSX Guideline	Does EPCOR Comply?	Comments
2) The majority of Directors should be "unrelated" (i.e. independent of management, and free from any interest and any business or other relationship which could, or could reasonably be perceived to, materially interfere with the Director's ability to act with a view to the best interests of the corporation, other than interests and relationships arising from shareholding).	Yes	All of the members of the Board are "outside" Directors (i.e. not members of management). Twelve of the thirteen members of the Board are unrelated Directors, and one may not be unrelated. The criteria used by the Board to determine the status of each Director are set out below.
The Board should include a number of Directors who do not have interests in or relationships with either the corporation or its significant shareholders.	Yes	Thirteen of the thirteen Directors have no interest in the Corporation or its Shareholder. Twelve of the thirteen Directors have no relationship with the Corporation or its Shareholder.
3) Disclose on an annual basis whether the Board has a majority of unrelated Directors and how that conclusion was determined.	Yes	The Board determines, on an annual basis, whether a member of EPCOR's Board is unrelated if they: • did not work for EPCOR • did not benefit from a business relationship with EPCOR that could reasonably be perceived to materially interfere with their acting in EPCOR's best interests • did not receive remuneration from EPCOR other than Director's fees and disbursements The Board also determines, on an annual basis, whether a Director has a relation to the Shareholder. Board of Directors: Hugh J. Bolton — Unrelated - Outside Janice G. Rennie — Unrelated - Outside Dan W. Boivin — Unrelated - Outside Mary Campbell Arnold — Unrelated - Outside Ronald J. Liteplo — Unrelated - Outside Steven E. Matyas — Unrelated - Outside M. Theresa McLeod — Unrelated - Outside Douglas H. Mitchell — A partner in a law firm providing legal services to EPCOR; may not be Unrelated; is Outside Dr. Michael J. Percy — Unrelated - Outside Robert L. Phillips — Unrelated - Outside Larry M. Pollock — Unrelated - Outside Christopher J. Robb — Unrelated - Outside Sheila C. Weatherill — Unrelated - Outside

TSX Guideline	Does EPCOR Comply?	Comments
4) Appoint a committee composed exclusively of outside (non-management) Directors, a majority of whom are unrelated, which committee is responsible for proposing new nominees to the Board and for assessing Directors on an ongoing basis.	Yes	The Governance and Nominating Committee (the "Committee") recommends procedures whereby the Shareholder appoints the chair and the Board. It also reviews, monitors and makes recommendations on orientation and education programs, and reviews the effectiveness of the Board and individual Directors. All of the members of the Committee are outside and unrelated Directors.
5) Implement a process for assessing the effectiveness of the Board, its committees and the contribution of individual Directors.	Yes	The Committee monitors the relationship between management and the Board, and recommends improvements. Directors are surveyed on the effectiveness of Board. The effectiveness of the Board and its committees is evaluated annually, and a peer review of individual Directors is conducted every second year.
6) Provide orientation and education programs for new Directors.	Yes	Procedures and policies for the orientation of Directors are in place. The Committee's Terms of Reference require review and recommendations for orientation and ongoing development of Directors. The Board is apprised of current risk conditions and governance practices, and provided with updates on business and regulatory initiatives. The Board identifies discussion topics for its annual planning retreat.
7) Consider size of the Board with a view to establishing a board size that facilitates effective decision-making.	Yes	As EPCOR evolves, the Board evaluates the skills and experience needed to guide the corporation. The Committee makes recommendations to the Board and to the Shareholder as appropriate.
8) The Board should review the adequacy and form of compensation of Directors and ensure the compensation realistically reflects the responsibilities and risk involved in being a Director.	Yes	The Committee's Terms of Reference prescribe regular review of Director compensation. The Committee considers time commitment, comparative fees, and responsibilities related to remuneration. The Chair makes recommendations to the Shareholder who determines Directors' compensation.

TSX Guideline	Does EPCOR Comply?	Comments
9) Board committees should generally be composed of outside Directors, a majority of whom are unrelated.	Yes	Each of the Board committees is composed of a majority of unrelated Directors, and is composed of entirely outside Directors. The Board's committees are: • Audit Committee • Environmental, Health and Safety Committee • Corporate Governance and Nominating Committee • Human Resources and Compensation Committee • Genesee 3 Oversight Committee Membership on each committee is reported on page 21 of this Annual Report.
10) Appoint a committee responsible for corporate governance issues, including developing responses to the TSX guidelines.	Yes	The Committee recommends policies and guidelines to the Board, and introduces initiatives to enhance corporate governance practices. The Committee's Terms of Reference require review and monitoring of compliance with recognized corporate governance guidelines.
11) Develop position descriptions for the Board and CEO which include limits to management's responsibilities, and approve or develop corporate objectives the CEO is responsible for meeting.	Yes	The Board acts in a plenary role, and sets out clear expectations for management. The mandate of the Board is defined in the corporation's bylaws, and in a Charter of Expectations. The Human Resources and Compensation Committee determines the CEO's objectives on an annual basis, and annually evaluates the CEO against these objectives.
12) The Board should establish procedures and structures that enable the Board to function independently of management, which structure could include a Chair who is not part of management or a Lead Director.	Yes	The Board has no management members. The Board functions independently of management and is chaired by the Chairman of the Board, who is not a management executive. The Board regularly meets without management present for a portion of its meetings.

TSX Guideline	Does EPCOR Comply?	Comments
13) All members of the Audit Committee should be outside Directors. The Audit Committee should have defined roles and responsibilities, and should have direct communication with internal and external auditors, and should review management reporting on internal controls.	Yes	All members of the Audit Committee are outside Directors. Several members have accounting designations, or other finance-related professional designations. The Audit Committee's Terms of Reference require all members to be financially literate. The Audit Committee has a written mandate that includes the monitoring of audit functions, the review of financial statements and internal control systems, the review of principal annual and quarterly public disclosure documents, and meeting with external auditors independently of management.
14) The Board should implement a system to enable individual Directors to engage outside advisors at the Corporation's expense, subject to the approval of an appropriate committee.	Yes	The Board of Directors functions independently of management. Individual Directors may engage an outside advisor at the expense of the Corporation, subject to approval by the Board or its committees.

Directors' Attendance

In 2003, the attendance of Directors at Board meetings was as follows:

Hugh J. Bolton	14 of 14 meetings	(100%)
Janice G. Rennie	14 of 14 meetings	(100%)
Mary Campbell Arnold	11 of 14 meetings	(79%)
Dan W. Boivin	13 of 14 meetings	(93%)
Ronald J. Liteplo	13 of 14 meetings	(93%)
Steven E. Matyas	6 of 8 meetings	(75%)
M. Theresa McLeod	12 of 14 meetings	(86%)
Douglas H. Mitchell	14 of 14 meetings	(100%)
Dr. Michael J. Percy	13 of 14 meetings	(93%)
Robert L. Phillips	14 of 14 meetings	(100%)
Larry M. Pollock	10 of 14 meetings	(71%)
Christopher J. Robb	14 of 14 meetings	(100%)
Sheila C. Weatherill	13 of 14 meetings	(93%)

Board of Directors

Office	Name, Municipality and Year appointed a Director		
Director, Chairman of the Board	Hugh J. Bolton (6)	Edmonton, Alberta	2000
Director, Vice-Chair of the Board	Janice G. Rennie (1) (3) (4)	Edmonton, Alberta	1993
Director	Mary Campbell Arnold (1)	Edmonton, Alberta	1998
Director	Dan W. Boivin (2) (5)	Calgary, Alberta	2002
Director	Ronald J. Liteplo (1) (2) (5)	Edmonton, Alberta	1999
Director	Steven E. Matyas	Toronto, Ontario	2003
Director	M. Theresa McLeod (1) (3)	Toronto, Ontario	2002
Director	Douglas H. Mitchell (2) (4)	Calgary, Alberta	2001
Director	Dr. Michael B. Percy (1) (3)	Edmonton, Alberta	1998
Director	Robert L. Phillips (4) (5)	Vancouver, British Columbia	1994-1999, re-appointed 2001
Director	Larry M. Pollock (3) (4)	Edmonton, Alberta	1998
Director	Christopher J. Robb (2) (4) (5)	Calgary, Alberta	1998
Director	Sheila C. Weatherhill (2) (3)	Edmonton, Alberta	2002

(1) Member of the Audit Committee

(2) Member of the Environmental, Health and Safety Committee

(3) Member of the Corporate Governance and Nominating Committee

(4) Member of the Human Resources and Compensation Committee

(5) Member of the Genesee 3 Oversight Committee

(6) Ex-Officio on all Committees

Officers

Donald J. Lowry	President and Chief Executive Officer
Brian Vaasjo	Executive Vice President and President, Energy Division
David R. Wright, Q.C.	Executive Vice President, General Counsel and Corporate Secretary
Mark D. Wiltzen	Senior Vice President and Chief Financial Officer
Glenn Kosak	Assistant Corporate Secretary
Stephen Muir	Vice President and Treasurer

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Financial Reporting

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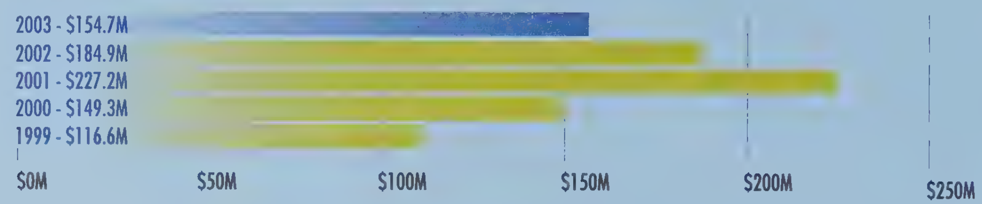
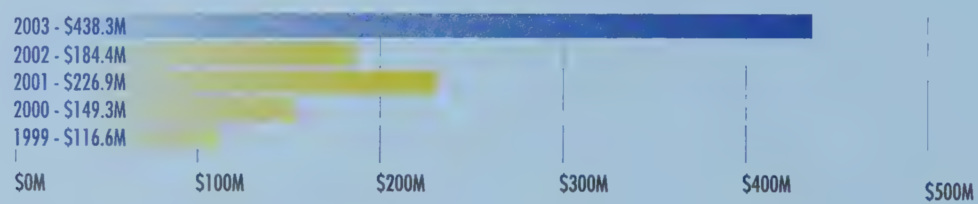
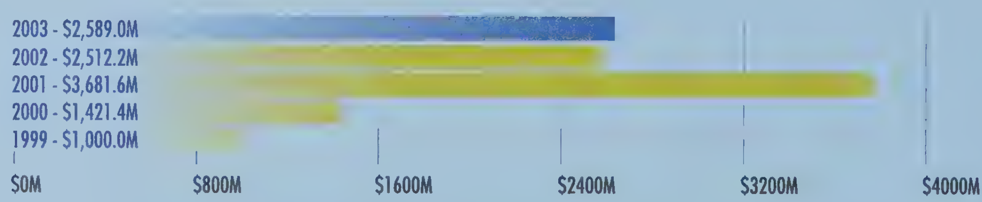
Net Income from Continuing Operations



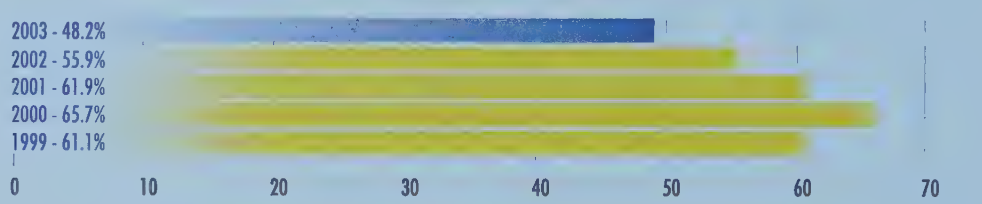
Net Income



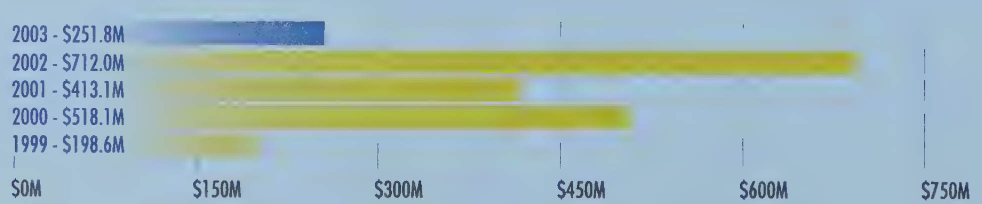
Total Revenue



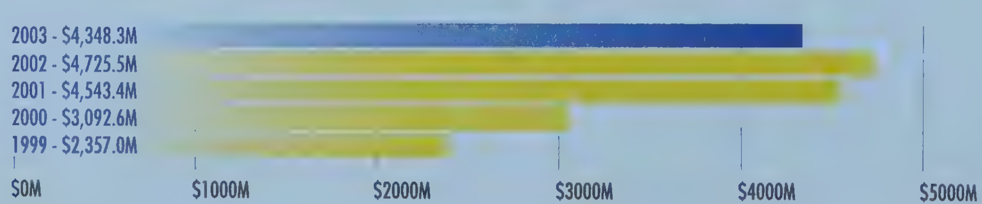
Debt To Capital (including preferred shares of subsidiary companies as capital)[1]



Capital Expenditures



Total Assets



[1] **Debt to Capital (including preferred shares of subsidiary companies as capital)** = (short-term debt+current portion long-term debt+long-term debt)/(short-term debt+current portion long-term debt+preferred shares of subsidiary companies+shareholder's equity)

Management's Responsibility

This management's discussion and analysis (MD&A) dated March 10, 2004 should be read in conjunction with the audited consolidated financial statements of EPCOR Utilities Inc. (the Company or EPCOR) for the years ended December 31, 2003 and 2002. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors.

Forward Looking Statements

Certain information in this report is forward looking and related to anticipated financial performance, events and strategies. When used in this context, words such as "will", "anticipate", "believe", "plan", "intend", "target", "expect" or similar words suggest future outcomes. By their nature, future events are subject to significant risks and uncertainties, which could cause EPCOR's actual results and experience to be materially different than the anticipated results. Such risks and uncertainties include, but are not limited to, operating performance, load settlement, regulatory and government decisions, weather and economic conditions, competitive pressures, construction risks, obtaining financing and the performance of partners, contractors and suppliers.

Strategy

EPCOR provides energy, water and energy related services, including electricity generation, distribution, transmission and marketing to end-use customers, natural gas marketing, and water purification, water distribution and wastewater services in Alberta, British Columbia, Ontario and the U.S. Pacific Northwest. This strategy is delivered through an integrated structure with a balanced portfolio of regulated and competitive businesses. The Company continues to look for opportunities for growth consistent with its balanced portfolio of businesses. By maintaining a strong base in regulated wires and water businesses and growing its commercial electricity operations, the Company intends to increase shareholder value as a leading North American supplier of energy services.

Key Performance Indicators

Performance of EPCOR in meeting the goals of its strategy is measured through both financial and non-financial measures that are approved by the Board of Directors. There are five measurement categories common to both the corporation and its business units operating within each business segment. The measurement categories at the corporate level are income, operational excellence, safety, environment and reputation.

There are specific measures within the operational excellence category within each business unit that are important in the operation of the respective unit. For example, in Generation, plant availability is the key measure of operational excellence. In the customer service area of Energy Services, the key measures relate to call answer and handle times. Environment and safety performance are measured based on both outcomes (for example, the number of incidents and accidents) and proactive activities (for example, applicable training) that are designed to minimize the potential for negative events. Business unit measures under the reputation category are focused on customer related measures relevant to the particular business unit, such as a customer satisfaction survey.

For 2003, EPCOR's performance against the business unit and overall targets was essentially on plan relative to the non-financial measures. For financial performance, earnings results for continuing operations were somewhat behind plan, while overall financial results were well ahead of plan due to the UE Waterheater Income Fund transaction – see Significant One-time Events and Results.

Consolidated Financial Information

($ millions)	2003	2002	2001
Revenues	$ 2,589.0	$ 2,512.2	$ 3,681.6
Preferred dividends paid by subsidiary companies	21.0	12.1	4.3
Income from continuing operations	154.7	184.9	227.2
Income (loss) from discontinued operations	283.6	(0.5)	(0.3)
Net income	438.3	184.4	226.9
Total assets	4,348.3	4,725.5	4,543.4
Long-term debt	1,700.6	1,905.4	1,702.1
Common dividends	110.5	100.5	90.5

Consolidated Results

Consolidated income from continuing operations decreased in 2003 to $154.7 million from $184.9 million in 2002 and from $227.2 million in 2001. The 2002 to 2003 decrease in income from continuing operations was primarily due to $31.0 million of decreased Alberta electricity margins, largely on wholesale contracts and the impact of government regulation to limit adjustments to previously billed amounts. Some of the adjustments to previously billed amounts were only identified as updated information was received from other participants in the Alberta electricity market. Increased bad debts expense and increased revenue reconciliation project costs of $10.0 million also reduced income from continuing operations. Other significant income impacts were due to $6.0 million of increased costs for energy portfolio administration offset by $8.0 million of decreased generation development costs and $8.0 million earned in connection with the Genesee Coal Mine joint venture.

The 2001 to 2002 decrease in income from continuing operations was due to a fourth quarter charge of $30.0 million to electricity revenues associated with unbilled consumption in Energy Services, increased customer service costs of approximately $15.0 million, higher generation development costs expensed during the year of approximately $14.0 million, higher bad debt expense of $8.0 million and a year-over-year decrease in the price of electricity.

The income from discontinued operations is discussed under Significant One-time Events and Results.

Consolidated revenues increased to $2.6 billion in 2003 from $2.5 billion in 2002 due primarily to a year-over-year increase in the price of electricity in Alberta and increased Ontario electricity revenues due to a full year of operations in 2003. The 2001 revenues of $3.7 billion reflected significantly higher electricity prices than in 2002.

Capital Spending and Investment

($ millions)	2003	2002
Generation – operated under Power Purchase Arrangements	$ 16.0	$ 23.9
Generation – commercial	135.2	340.2
Distribution and Transmission	39.9	46.6
Energy Services	21.1	39.9
Water Services	30.4	26.2
Corporate and other	9.2	3.7
Business acquisitions	–	231.5
	$ 251.8	$ 712.0

Capital spending and investment, including interest capitalized on construction, was $251.8 million in 2003 compared with $712.0 million in 2002. Capital expenditures in 2003 included continued construction of the Genesee Phase 3 plant in Alberta and the completion of construction of the Miller Creek plant in British Columbia. In January 2003, the Company sold 50 per cent of its interest in Genesee Phase 3 to TransAlta Corporation while the Miller Creek plant was commissioned in October 2003 but is not expected to be fully operational until the second quarter of 2004. Capital investment in 2002 included costs to complete the construction of the Frederickson plant, located in Washington State, and continued construction of the Miller Creek plant and the Genesee Phase 3 plant. In addition, the Company purchased water heater assets, electricity and natural gas retail contracts and water heater rental agreements from Ontario Hydro Energy Inc. in April 2002 and acquired its partner's 60 per cent interest in Frederickson Power L.P. in August 2002.

Significant One-time Events and Results

Exit from Competitive Mass Market

In August 2003, the Company announced its decision to concentrate its national energy business on growth opportunities in commercial, industrial and wholesale markets as well as generation. As a result of this decision, EPCOR ceased offering electricity and natural gas competitive contracts to residential, farm and small commercial customers and reviewed its strategic options for its Union Energy branded rental, financial and heating, ventilation and air-conditioning (HVAC) business in Ontario. The Company's exit from the competitive mass market contracts business did not have a significant financial impact on operations and it continues to service existing mass market contracts. EPCOR continues to provide regulated electricity services to residential, farm and small commercial customers in Alberta under the Regulated Rate Tariff (RRT) which remains a core part of EPCOR's integrated energy strategy.

Disposal of Union Energy

In the fourth quarter, the Company disposed of its investment in its subsidiaries, Union Energy Inc. and EPCOR Energy Securitizations Inc. (collectively Union Energy), thereby exiting the water heater rental and related financing businesses that it acquired in 2001. The disposal was effected through and resulted in the formation of the UE Waterheater Income Fund (the Fund), that now operates these businesses independently of EPCOR. The proceeds on disposal (after underwriters' fees) were $793.3 million resulting in a gain of $291.1 million. This gain is included in income from discontinued operations in the consolidated statement of income.

The proceeds on disposal included 5,413,000 units of the Fund issued to the Company in accordance with the over-allotment provisions of the underwriting agreement. Subsequent to year-end, the underwriters exercised their over-allotment option and the Company exercised its option to sell these units to the Fund for cash proceeds of $51.3 million.

Purchase of Medium-term Notes

In the fourth quarter, EPCOR purchased $221.0 million of its outstanding 4.6 per cent medium-term notes (MTNs), due 2005, out of an original issue of $300.0 million. The purchase was funded from cash and available credit facilities in contemplation of the disposal of Union Energy and the Company paid a premium of $4.3 million to complete the purchase.

Energy Services Revenues and Bad Debts

In 2003, the Company undertook an unbilled revenue reconciliation project to identify billing discrepancies. As revised load, pricing and settlement information was received from other Alberta electricity market participants, a new Government of Alberta regulation prevented billing corrections to be charged to regulated customers after a specified time limit. The Company reduced revenues by $19.0 million consisting of approximately $12.5 million for these unbilled revenue adjustments plus approximately $6.5 million for late consumption adjustments received from a wire service provider.

In the fourth quarter, the Company recorded a bad debt expense of approximately $6.0 million for the estimated portion of its 2001 Regulated Rate Tariff Collection Shortfall balance receivable that will not be collectible. The write-down was based on estimated collections remaining from the customer base, which are lower than original estimates. The estimated collections are lower because actual customer consumption was lower than the expected consumption used in estimating the original receivable and there has been customer attrition which lowered the collection base.

Generation Other Income

The Company earned a non-recurring fee of $8.0 million in the first quarter of 2003 in connection with the change in control of the Company's joint venture partner in the Genesee Coal Mine.

Segment Results

Generation

Generation earns income from generation plants operating under Power Purchase Arrangements (PPAs) and from commercial power generation plants. The Company's Genesee, Rossdale, and Clover Bar power plants, previously rate-regulated through annual tariff applications, became subject to PPAs effective January 1, 2001 while continuing to be rate-regulated as determined under the guidelines of the *Electric Utilities Act* (Alberta). The electricity generated from the plants operating under PPAs is provided to the PPA holders, not the owner-operators of the plants. In exchange for the rights to the electricity, the Company receives formula-based fixed capacity and variable payments which are intended to provide the Company with a reasonable opportunity to recover plant operating costs and provide a fair rate of return (the return on equity component is set at 4.5 per cent over the rate of long Canada bonds). In addition, the Company receives incentives and pays penalties when the output available from the plant exceeds or falls below committed capacity levels as set out in the PPAs. The committed capacity levels in the PPAs were originally set with the expectation that the incentives and penalties would net out over the life of the PPAs. While the plants operating under PPAs are rate-regulated under the *Electric Utilities Act* (Alberta), they do not meet the criteria for rate-regulated accounting under generally accepted accounting principles. Accordingly, the plants are accounted for as non-rate-regulated facilities in accordance with the commercial terms and conditions inherent in the PPAs. Key to the earnings of plants operating under PPAs is controlling costs and ensuring that the plants are able to meet or exceed the committed capacity levels set out in the PPAs. The Rossdale PPA expired on December 31, 2003 and the plant will be operated as a commercial generation plant from that point forward. PPA availability incentives of $5.3 million for Rossdale since 2001 were recognized in income in 2003.

Electricity generated from commercial generation plants is sold either under long-term conitracts to creditworthy third parties or into the wholesale market where the plant is located. The Company's general objective is to ensure that at least 50 per cent of its commercial plants' capacity is sold under contract. Key to the earnings of these plants is ensuring that the plants are dispatched (directed to supply electricity to the grid) as economically as possible, operating costs, including fuel, are appropriately controlled and that the plants are well maintained.

Generation operating results		2003	2002
(including intersegment transactions; $ millions)			
Revenues		$ 493.5	$ 474.9
Expenses	Operating	291.7	303.4
	Financing	115.1	93.8
	Income taxes	32.8	36.0
		439.6	433.2
Net income		$ 53.9	$ 41.7
Electricity generation (000s of megawatt-hours)[1]			
Coal generating units		6,209	6,411
Natural gas generating units		1,313	1,386
Hydro generating units		84	81
Wind generating unit		3	2
		7,609	7,880

[1] Excludes generation from plants not yet considered fully operational.

Generation's net income increased $12.2 million in 2003 from 2002 due to lower turbine contract rights cancellation costs, a non-recurring fee received in connection with the change in control of the Company's joint venture partner in the Genesee Coal Mine and increased contributions from the Frederickson plant resulting from the arrangement with Energy Services to sell the plant's output not secured by long-term contracts. The Frederickson plant commenced commercial operation in September 2002.

Higher revenues in 2003 mainly reflect a full year of Frederickson plant operations. In the first quarter, the Company received a payment in connection with the Genesee Coal Mine joint venture. Even though the Company's Frederickson plant had a full year of commercial operations in 2003, total generation across all EPCOR plants decreased from 2002 by 271 thousand megawatt-hours (MWh). This was due to lower generation from the Company's Genesee plant reflecting more scheduled maintenance outages in 2003 compared to 2002. In addition, generation from the Company's Clover Bar and Rossdale plants decreased due to the addition of new, more efficient generating units within the province of Alberta.

Generation operating costs decreased in 2003 from the prior year due largely to the lower generation volumes and lower costs associated with generation development activities. In 2002, the Company incurred costs associated with cancelling a turbine contract. There was no comparable cost in 2003. Partially offsetting the reduced operating costs in 2003 were the incremental operating costs of the Frederickson plant.

Generation financing costs increased by $21.3 million in 2003 from 2002 as a result of the full year's impact of increased debt to finance the Company's Frederickson plant.

In 2004, Generation management will focus on the continued construction of the Genesee Phase 3 generation plant located in Alberta. Construction is currently on time and on budget with expected commissioning of the plant in the first quarter of 2005. Ownership of the plant and interest in its future operations is shared with TransAlta Corporation. Generation will also focus on improving the operating efficiencies of its various plants by continuing to achieve strong plant availability by minimizing outage times and by optimizing operations and maintenance expenses. By the second quarter of 2004, the Company expects the finalization of an agreement for the sale of a 49.85 per cent interest in its Frederickson plant. At that point, the Company's share of generation from this plant will be fully secured under long-term contracts. As its associated PPA expired on December 31, 2003, the Rossdale plant is now operated as a commercial plant with an operating strategy consistent with expected demands of the plant. The City of Edmonton has requested that the Company provide its outlook and future plans for the Rossdale plant and the site that it occupies by the end of 2004.

Energy Services

Energy Services earns income through the provision of electricity and natural gas to end-use customers in Alberta and Ontario. Electricity revenues are earned through the sale of electricity under regulated rates or rates set by contracts, both designed to cover the costs of supplying electricity (including the commodity cost, the distribution and transmission charges, credit risk, and electricity price and volume risks) and provide a competitive margin. Natural gas revenues are earned through sales of natural gas under contract at rates that are designed to cover the costs of supplying natural gas (including the commodity cost and costs related to transportation, credit risk, and natural gas price and volume risks) and provide a competitive margin.

The merchant group within Energy Services manages the Company's overall electricity and natural gas portfolio. This group aggregates the generation and the electricity and natural gas required to serve estimated customer demands in all markets in which the Company operates. It does this by entering into financial contracts and purchasing and selling electricity under physical contracts and, where or when required, in the spot market. The merchant group takes the required actions to balance the Company's electricity and gas portfolios on a real time basis under prudent risk management policies. In 2000, the Company purchased the PPAs associated with TransAlta Utilities Corporation's (TransAlta) Sundance generating station (units 5 and 6) and Alberta Power (2000) Ltd.'s (ATCO) Battle River generating station. The electricity provided under these PPAs, in addition to that produced from the Company's commercial plants, is used to help balance the Company's electricity portfolio and satisfy customer electricity requirements. As part of its mandate, the merchant group also participates in the ancillary services (electricity reserves) market. Until mid-December 2003, Energy Services also earned income through the rental of water heaters, the provision of HVAC services and through financing HVAC equipment sales, all primarily in Ontario. This comprised the Union Energy business, which was disposed of in December 2003.

Energy Services operating results		2003	2002
(including intersegment transactions, $ millions)			
Revenues	Energy sales	$ 1,938.9	$ 1,825.0
	Commercial and other	28.6	24.2
		1,967.5	1,849.2
Expenses	Operating	1,908.6	1,721.3
	Financing	47.6	37.7
	Income taxes	10.7	30.6
		1,966.9	1,789.6
Income from continuing operations		0.6	59.6
Net (loss) from discontinued operations		(7.5)	(0.5)
Net (loss) income		$ (6.9)	$ 59.1
Retail consumption			
Electricity (000s of megawatt-hours)		15,094	14,524
Natural gas (000s of gigajoules)		12,967	13,928

Energy Services' income from continuing operations decreased significantly in 2003 from 2002, due to decreased Alberta electricity margins as pricing, load and settlement adjustments relating to prior years were received and recorded in the current year, and due to higher bad debt expense relating to deferred amounts receivable.

During 2003, the Company continued to experience challenges in billing its Alberta electricity customers. Several projects were undertaken and significant resources were committed to address these challenges. Energy Services received prior period load and consumption adjustments from wire service providers, which it was not able to bill to customers because, in June

2003, the Regulated Default Supply regulation was amended to prevent the Company from billing regulated amounts that are more than one year past the original billing date. Revenues were also reduced during the year to reflect lower revised estimates of unbilled revenues associated with sites for which consumption charges were received but were not billed or otherwise recovered from the wires service provider. The aggregate adjustment associated with billing limitations and reducing unbilled revenues was approximately $37.0 million.

The Company also increased its bad debt provision by $6.0 million to recognize uncollectible amounts related to its deferred amounts receivable balance. The Company has taken a number of measures and has made progress toward ensuring billings are complete and timely and that accrued unbilled revenues do not include unbillable amounts.

Energy sales include retail electricity and retail natural gas sales in Alberta and Ontario. Energy sales increased from 2002 by $113.9 million, primarily due to higher Alberta electricity prices in 2003. Additional energy sales were also realized in 2003 from approximately 395,000 electricity and natural gas retail contracts acquired from Ontario Hydro Energy Inc. in the second quarter of 2002.

Operating expenses in 2003 increased significantly from 2002 mostly as a result of higher Alberta electricity prices in 2003. Also contributing to the increased costs were increased customer service costs, higher bad debt expense and a full year's operating costs of the Ontario electricity and natural gas contracts acquired in 2002.

Certain of Energy Services' electricity operations in Edmonton are subject to the Payment in Lieu of Tax Regulation and subsidiaries that provide retail and wholesale services outside of Edmonton are taxable under federal and provincial tax legislation. Income taxes were lower in 2003 than in 2002 due to lower taxable income and lower tax rates.

In 2003, the Company commenced a legal action against Aquila Networks Canada (Alberta) Ltd. and certain of its affiliates regarding load settlement and related issues. The lawsuit is presently before the courts.

In 2004, Energy Services' primary focus will be on continuing to improve billing completeness and timeliness of billing corrections, customer service and to reduce adjustments from wire service providers based upon the initiatives undertaken and established in 2003 for its Alberta customers.

Distribution and Transmission

Distribution and Transmission principally earns income by transmitting high voltage electricity from generation plants to points of distribution and from there, distributing low voltage electricity to retailers' end-use customers. The Company's distribution and transmission assets are located in and around the city of Edmonton. The Company earns a provincially regulated transmission tariff intended to allow the Company to recover its prudent operating and maintenance costs in addition to providing a fair rate of return on its transmission infrastructure. For its Distribution operations, the Company earned its revenues under a Performance Based Rate (PBR) structure established in 2001 and regulated by Edmonton City Council. Under the PBR, the Company earned a distribution tariff levied on all retailers who access the low voltage wires in the city of Edmonton. The Company is also responsible for meter reading for all electricity suppliers within the city of Edmonton service area and acting as the load settlement agent for the City of Edmonton and the Town of Ponoka.

In addition to providing electricity transmission and distribution services, the Company also earns complementary income through competitive contract-based commercial services related to maintaining and repairing streetlighting, traffic signal, light rail transit and trolley facilities.

Distribution and Transmission operating results		2003	2002
(including intersegment transactions; $ millions)			
Revenues	Distribution	$ 154.1	$ 160.1
	Transmission	32.1	34.0
	Commercial and other	36.3	31.0
		222.5	225.1
Expenses	Operating	170.9	176.0
	Financing	16.5	14.9
		187.4	190.9
Net income		$ 35.1	$ 34.2

Distribution and Transmission's net income increased slightly in 2003 from 2002, even though revenues decreased, due mainly to overall higher margins based on the mix of volume and rate classes. Financing expenses increased in 2003 compared to 2002 as interest recoveries related to the collection of the 2000 Distribution Deferral Rider decreased.

In 2004, Distribution and Transmission will focus on construction related to continued growth within the City of Edmonton and replacing aging infrastructure. Under the *Electric Utilities Act* (Alberta), regulation of Distribution transferred from Edmonton City Council to the Alberta Energy and Utilities Board (AEUB) effective January 1, 2004. The change of regulator terminated the PBR and returns Distribution to a traditional cost of service methodology under which it is expected to recover all just and reasonable costs plus a return on investment under an AEUB approved tariff. The formal Distribution tariff hearings for 2004 are in progress. Also in 2004, Distribution and Transmission will be preparing and submitting their 2005 through 2007 General Tariff Applications for both its distribution and transmission businesses.

Water Services

Water Services primarily earns income from the treatment, distribution and sale of drinking water while ensuring public health standards are exceeded. The majority of Water Services income is earned through a PBR tariff charged to its Edmonton customers. The PBR tariff provides for Water Services to recover its costs and earn a fair return while also providing an incentive to maintain costs below the inflationary adjustment built into the PBR rate. The key to maintaining earnings on water sales is to provide sufficient quantities of high quality water while controlling costs. Water Services' also earns incremental income through competitive contract-based water and wastewater services to commercial, industrial and municipal customers. The key to earning satisfactory margins on these contracts is to satisfy the terms of the contract while controlling or reducing operating costs.

Water Services operating results		2003	2002
(including intersegment transactions; $ millions)			
Revenues	Water sales	$ 106.2	$ 106.4
	Commercial and other	22.7	24.1
		128.9	130.5
Expenses	Operating	87.3	83.3
	Financing	18.3	16.6
		105.6	99.9
Net income		$ 23.3	$ 30.6
Water sales (megalitres)		121,467	126,610

Net income decreased in 2003 from 2002 mainly due to increased financing expenses resulting from increased long-term debt at a higher cost than the short-term financing that it replaced, higher consulting fees and higher future employee benefits. In addition, the margin on commercial services activities decreased as higher expenses were incurred.

The 2003 water sales revenues were consistent with 2002 water sales revenues while revenues from commercial activities were slightly lower due to fewer capital improvement projects for construction of water treatment and distribution facilities in southern Alberta locations.

In 2004, Water Services will focus on operating efficiencies as it enters its third year of the PBR structure. Water Services expects that it will continue to meet or exceed the performance criteria contained within the PBR Bylaw. In addition, commercial services opportunities will be pursued, primarily with Alberta industrial customers. Water Services will continue to market its expertise in the water and wastewater utility services businesses to municipal customers.

Fourth Quarter Results

Net income for the fourth quarter of 2003 was $309.3 million compared to $25.4 million for the fourth quarter of 2002.

Income from continuing operations in the fourth quarter of 2003 was $29.6 million compared with $25.1 million in the fourth quarter of 2002. The results were higher than 2002 since there was no material revenue charge recorded in the fourth quarter as there was in the prior year. This increase was offset by increased bad debt expense on deferred amounts receivable and the charge for prior period energy costs charged by a wires service provider that is not recoverable due to the billing correction time limitation invoked in 2003.

The 2003 fourth quarter income from discontinued operations includes a $291.1 million gain on disposal of Union Energy and loss from operations of $11.4 million, which compares to income from discontinued operations of $0.3 million in the fourth quarter of 2002.

Consolidated Balance Sheet

Consolidated assets decreased $377.2 million in 2003 to $4.3 billion at December 31, 2003 from $4.7 billion at December 31, 2002. The decrease in assets in 2003 was mainly due to the Company's divestiture of Union Energy and 50 per cent of its interest in the Genesee Phase 3 power plant project and the use of the associated cash to repurchase debt and make contractual debt payments. Assets were further reduced by the amortization and depreciation of various assets (offset by capital additions) and reduction of deferred amounts receivable. Collection of amounts pertaining to deferred amounts receivable, consisting of the 2000 Distribution Deferral Rider and 2001 Regulated Rate Tariff Collection Shortfall Rider accounts, commenced in 2002 and was substantially completed by the end of 2003.

Capital Investment

In 2003, the Company invested $251.8 million in capital projects compared with $712.0 million in 2002. The majority of the $460.2 million decrease was due to the divestiture of a 50 per cent interest in the Company's Genesee Phase 3 power plant project and decreased spending on other major projects such as Frederickson which commenced operations in September 2002.

Deferred Amounts Receivable and Deferred Utility Obligation

In 2000, as approved by its regulator, the Company established the 2000 Distribution Deferral Rider entitling it to collect certain electricity costs incurred in 2000 in future years. This deferred account balance was fully collected by December 31, 2003.

In November 2000, the Government of Alberta imposed an 11 cents per kilowatt-hour limit on the amount that could be collected from RRT customers in 2001. In the second quarter of 2002, the AEUB approved the 2001 Regulated Rate Tariff Collection Shortfall account balance, associated with the Aquila Networks Canada (ANC) service area, to be collected over a two-year period that is expected to end in the first quarter of 2004. In the third quarter of 2002, the City of Edmonton issued a Compliance Certificate, thereby approving the 2001 Regulated Rate Tariff Collection Shortfall balance associated with the Company's Edmonton service area, to be collected over a two-year period expected to end in the first quarter of 2004.

Effective October 5, 2002 and October 1, 2002 respectively, as recommended by the AEUB, the Company sold the 2000 Distribution Deferral Rider and 2001 Regulated Rate Tariff Collection Shortfall Rider deferred account balances related to the Edmonton and ANC service areas to an unrelated trust for $225.0 million cash. Under generally accepted accounting principles, the transaction was accounted for as a financing arrangement rather than a sale. As a result, the cash received was recorded as a deferred utility obligation rather than a reduction of deferred amounts receivable. The Company remains the collection agent for the deferred amounts receivable. The balance of the deferred utility obligation will be drawn down as the deferred amounts receivable are collected from customers and remitted to the trust.

In the fourth quarter of 2003, the Company wrote off $6.0 million to bad debt expense with respect to the 2001 Regulated Rate Tariff Collection Shortfall deferred amounts receivable based on an expected shortfall in the final collection of these balances. The shortfall was due to lower consumption than originally estimated in establishing the receivable and higher than expected customer attrition. At December 31, 2003, the 2000 Distribution Deferral Rider has been fully collected and remitted to the trust while the 2001 Regulated Rate Tariff Collection Shortfall is expected to be fully collected from customers and remitted to the Trust by the end of 2004. At that point, the Company will no longer be reporting any balances outstanding for both deferred amounts receivable and the related deferred utility obligation.

Future Income Tax Asset

On January 1, 2001, the Payment in Lieu of Tax Regulation (PILOT regulation) under the *Electric Utilities Act* (Alberta) came into effect requiring certain of the Company's operations, that are exempt from taxation, to pay amounts in lieu of income taxes in exactly the same manner as if they were taxable under federal and provincial tax laws. Accordingly, under the regulation, on January 1, 2001, these operations were deemed to have disposed of and re-acquired their assets at fair market value. The Company determined that the resulting tax bases of these assets were greater than their book values giving rise to a future tax benefit associated with the additional deductions available for tax purposes. Under generally accepted accounting principles, the future tax benefit associated with the additional tax deductions available was recognized as a future tax asset in the balance sheet. Since the initial recognition of the future tax was the result of legislation and did not contribute to current earnings, the corresponding adjustment was recorded as an adjustment to retained earnings in 2001.

Alberta Revenue, Tax and Revenue Administration (Alberta Revenue), as agent for the Balancing Pool of Alberta, is responsible for assessing the Company's amounts in lieu of income tax returns filed under the PILOT regulation. In July 2003, Alberta Revenue notified the Company that it is its view that the value of goodwill for amounts in lieu of income tax purposes for its generation assets operating under PPAs, as determined by the Company at the date that the Company first became subject to the PILOT regulation, is overstated. If the value of the Company's goodwill for PILOT purposes is determined to be less than the amount established by the Company on January 1, 2001, certain deductions for amounts in lieu of income tax purposes would decrease. This would result in additional amounts in lieu of income taxes payable and the future amounts in lieu of income tax asset associated with such deductions being written down as an income tax expense. At January 1, 2001, the balance of the future amounts in lieu of income tax asset associated with the goodwill was $112.9 million, based on an estimated fair market value of goodwill of $400.0 million.

The Company believes that it appropriately measured the value of goodwill subject to the PILOT regulation and will continue to defend its position. No valuation provision has been made against the future amounts in lieu of income tax asset and no provision has been made in the financial statements for additional amounts in lieu of income taxes, if any, which may be determined to be payable. Alberta Revenue's valuation review is ongoing and the timing of its completion is uncertain.

Liquidity and Capital Resources

($ millions)	2003	2002	2001
Cash flow from operations[1]	$ 323.1	$ 399.5	$ 441.5
Cash flow from operating activities	557.7	537.5	(81.2)
Long-term borrowings during the year	–	300.0	552.7
Medium-term notes purchased during the year	(221.0)	–	–
Preferred shares issued by subsidiary companies (net of issue costs) during the year	(0.1)	193.4	150.0
Cash and cash equivalents (bank indebtedness), at end of year	414.5	14.6	(14.2)
Short-term debt, at end of year	(116.7)	(182.4)	(510.8)
Ratios[1]			
Debt to equity[2]	48:52	56:44	62:38
Interest coverage on long-term debt:			
Income before interest and taxes[3]	2.4 X	3.0 X	3.6 X
Income from continuing operations before interest and taxes[4]	2.5 X	3.1 X	3.6 X
Income before interest, taxes, depreciation and amortization[5]	3.6 X	4.2 X	4.7 X
Income from continuing operations before interest, taxes, depreciation and amortization[6]	3.8 X	4.4 X	4.7 X
Cash flow to interest bearing debt (%)[7]	17.8	19.2	19.9
Credit ratings			
Standard & Poor's Short-term debt	A-1 (Low)	A-1 (Low)	A-1 (Low)
Long-term debt	BBB+	BBB+	A-
Preferred shares of subsidiary companies[8]	P-2 (Low)	P-2 (Low)	P-2
Dominion Bond Rating Service Short-term debt	R-1 (low)	R-1 (low)	R-1 (low)
Long-term debt	A (low)	A (low)	A (low)
Preferred shares of subsidiary companies[8]	Pfd-2 (low)	Pfd-2 (low)	Pfd-2 (low)

1 Cash flow from operations and ratios in this table are non-GAAP financial measures and do not have any standardized meaning prescribed by generally accepted accounting principles and are unlikely to be comparable to similar statistics published by other companies. They are presented since they are commonly referred to by debt holders and other interested parties in evaluating the Company's financial position and in assessing its credit worthiness.

2 Debt to equity is expressed as a ratio, of debt as a percentage of total capital, over equity as a percentage of total capital. Debt is equal to short-term debt plus long-term debt (including the current portion). Equity is equal to preferred shares issued by subsidiary companies, plus shareholder's equity. Total capital is equal to short-term debt, plus long-term debt (including the current portion), preferred shares issued by subsidiary companies and shareholder's equity.

3 Income before interest and taxes is equal to operating income before financing expenses divided by interest on long-term debt.

4 Income from continuing operations before interest and taxes is equal to operating income before financing expenses divided by interest on long-term debt for continuing operations.

5 Income before interest, taxes, depreciation and amortization is equal to operating income before financing expenses adding back depreciation and amortization, divided by interest on long-term debt for continuing operations.

6 Income from continuing operations before interest, taxes, depreciation and amortization is equal to operating income before financing expenses adding back depreciation and amortization, divided by interest on long-term debt.

7 Cash flow to interest bearing debt (expressed as a percentage) is equal to cash flow from operations divided by short-term debt plus long-term debt (including the current portion).

8 2002 and 2003 ratings of preferred shares of subsidiaries relate to EPCOR Preferred Equity Inc. and EPCOR Finance Corporation. 2001 ratings of preferred shares of subsidiaries relate to EPCOR Finance Corporation only.

Cash flow from operations, which constitutes net income adjusted for non-cash items, decreased in 2003 to $323.1 million from $399.5 million in 2002 while cash flow from operating activities increased to $557.7 million from $537.5 million. The decrease in cash flow from operations consists primarily of the decrease in income from continuing operations and an increase in income taxes paid during the year. The increase in cash flow from operating activities consists primarily of increased collections of deferred amounts receivable offset by the decrease in cash flow from operations.

The Company maintains bank lines of credit of $850.0 million of which $800.0 million (2002 – $800.0 million) are committed term lines for the purpose of providing short-term capital and letters of credit. At December 31, 2003, the Company had $224.3 million (US$173.0 million) outstanding under the committed credit facility. The committed bank lines back the Company's commercial paper program, which has an authorized capacity of $500.0 million. There was no commercial paper issued and outstanding at December 31, 2003 (2002 – $182.4 million). At December 31, 2003, $29.3 million (2002 – $49.5 million) of letters of credit were outstanding. The letters of credit are mainly issued to satisfy security requirements of counterparties from which the Company purchases wholesale electricity and natural gas, and to satisfy legislated reclamation requirements.

In November and December 2003, the Company repurchased $221.0 million of its $300.0 million medium-term notes due January 2005. The premium of $4.3 million paid upon these repurchases has been included in financing expenses.

The Company paid common dividends in 2003 of $110.5 million (2002 – $100.5 million) to its sole common shareholder, the City of Edmonton. In accordance with the Company's dividend policy, common dividends payable in 2004 will be $120.5 million, comprised of a regular and special dividend. The Company's dividend policy stipulates that the regular dividend will increase by $10 million in each year until the dividend reaches 60 per cent of earnings available to common shares of EPCOR in the applicable year. Thereafter, the dividend will be the greater of the previous year's dividend adjusted for the change in the consumer price index or 60 per cent of earnings available to common shares of EPCOR in the applicable year subject to significant change in the Company's business or financial condition. It is expected that the 60 per cent threshold will be reached in 2004.

The Company paid dividends on preferred shares issued by its subsidiaries, EPCOR Finance Corporation and EPCOR Preferred Equity Inc., totaling $21.0 million (2002 – $12.1 million). The increase in dividends resulted from dividends for a full year on preferred shares issued at the end of September 2002.

The Company is committed to fund various capital projects, most predominantly Genesee Phase 3. The total amount of committed capital funding at December 31, 2003 was $51.8 million (2002 – $244.2 million). Although not committed, the Company has budgeted average annual capital requirements of approximately $110.0 million for infrastructure maintenance (distribution, transmission, water and generation operating under PPAs).

On October 31, 2003, the Company entered into an agreement for the sale of a 49.85 per cent interest in its Frederickson generation plant to Puget Sound Energy, Inc. The sale is subject to regulatory approvals and is not expected to be finalized until the second quarter of 2004. The agreed purchase price is approximately $107.7 million subject to foreign exchange and closing adjustments. An expected loss of approximately $10.1 million, comprised of book and foreign exchange losses, will be recorded as a loss on disposal of assets in 2004 when the sale is finalized.

In 2004, the Company has principal repayment obligations on its long-term debt totaling $55.6 million (2003 – $66.1 million). Capital expenditures net of proceeds on plant disposal are projected to be consistent with 2003 expenditures. Cash on hand and operating cash flows are expected to be the source of funds from which debt repayment obligations and capital programs will be funded in 2004.

In 2003, Dominion Bond Rating Service reaffirmed the Company's credit rating at A(low) while Standard and Poor's credit rating of the Company remained unchanged at BBB+. Given the current state of the electricity markets in general with excess generating capacity, relatively high natural gas prices and environmental uncertainties, bond rating agencies are continuing to pressure energy providers and the industry in general, to better manage debt and maintain adequate cash flow to service debt obligations. While the change in ratings that occurred in 2002 is not expected to have an impact on the Company's future financing plans, further downgrades would likely result in increased interest costs and reduce the sources for investment capital.

New Accounting Standards in 2003

In 2003, the Company adopted several new accounting standards as recommended by the Canadian Institute of Chartered Accountants (CICA), the organization responsible for establishing accounting standards in Canada. The standards and their impact on the Company are described below:

Disclosure of Guarantees

Effective for interim periods commencing on or after January 1, 2003, generally accepted accounting principles require expanded disclosure of corporate guarantees. The new guideline requires, among other things, disclosure of the nature, terms, triggering events, potential amount of future payments and collateral provision related to corporate guarantees.

The Company has disclosed its standby letters of credit and indemnity of certain liabilities of Union Energy in its notes to the consolidated financial statements. There are no other significant third-party guarantees.

Disposal of Long-lived Assets and Discontinued Operations

This new standard applies to disposal activities initiated by an enterprise's commitment to a plan on or after May 1, 2003. The standard provides guidance with regard to the identification, measurement and disclosure of any long-lived assets not held for use and any discontinued operations. The Company adopted the standard in reporting its disposal of Union Energy including non-branded HVAC businesses and will apply it to future disposals of long-lived assets and discontinued operations.

Future Accounting Changes

Several new accounting standards have been approved for application in the future by the CICA. The approved standards that apply to the Company, as well as the Company's proposed application of the standards, are described below:

Impairment of Long-lived Assets

For fiscal reporting periods commencing on or after April 1, 2003, generally accepted accounting principles require that the impairment of long-lived assets be tested under a two-step process whereby an impairment is identified when the carrying amount of an asset exceeds the sum of undiscounted cash flows expected to result from its use and eventual disposition. If an impairment is identified, the second step is to recognize an impairment loss measured as the amount that the long-lived asset's carrying amount exceeds its fair value. The Company has adopted the new recommendations prospectively in accordance with the effective date.

Asset Retirement Obligations

Effective for fiscal periods beginning on or after January 1, 2004, a new asset retirement obligations (ARO) standard requires the recognition of any asset retirement obligations at fair value when incurred, unless the fair value cannot be reasonably determined. When the liability is recognized, a corresponding asset retirement cost is added to the carrying amount of the related asset and is depreciated over the estimated useful life of the related asset. Increase of the liability due to the passage of time is an operating expense. Implementation of the new standard is expected to result in an immaterial change to property, plant and equipment balances as well as the related net liability balances. The set-up of a new asset retirement obligation will be offset by the reversal of the previously recorded decommissioning liability. The after-tax cumulative effect of the change in accounting policy is also expected to be immaterial but will be recorded in the first quarter of 2004 on a retroactive basis with restatement of prior periods resulting in an expected increase to retained earnings. These changes are the result of the estimated decommissioning liability previously recognized in the accounts being greater than the estimated fair value of the legal asset retirement obligations.

Hedging Relationships

For fiscal years beginning on or after July 1, 2003, generally accepted accounting principles will apply a more restrictive qualification to hedging relationships for hedge accounting. This will reduce the number of relationships previously considered to qualify for hedge accounting. The impact of the new accounting standard will be that certain derivative financial instruments, which give rise to financial assets or financial liabilities, that will no longer qualify as hedges, will be recognized in the balance sheet and measured at fair value, with changes in fair value recognized at each reporting date in income instead of accounting for the contracts under the accrual method. On initial adoption of this standard, there will be net fair value losses that will be deferred and amortized over the life of the underlying contracts. The Company has identified three separate types of financial instruments that do not meet the new hedging standards and will therefore require fair value measurement. The most significant of these transactions is a contract-for-differences on the Joffre generation plant. The other transactions are a portion of Ontario electricity forward financial purchases and Ontario financial transmission contracts. The result will be that Generation and Energy Services operating results will show more variability and involve more estimates. More estimates will be required due to the general illiquidity of power markets and the consequent limited availability of robust forward market prices for use in fair market value determinations. The Company has adopted the new accounting standard effective January 1, 2004.

Significant Accounting Policies

Revenue Recognition Under PPAs

The Company recognizes electricity revenue from its generating units operating under PPAs at the long-term price of power embedded in the PPA, including estimated penalties and incentives. Under this method, net incentives are generally deferred since these are long-term arrangements that were designed such that the incentives and penalties are expected to offset each other over the terms of the respective PPAs. The degree to which incentives are recognized will change if the estimated long-term price embedded in the PPA is modified due to revisions to the long-term outlook of the plants based on historical performance, planned maintenance, reliability and plant availability.

Financial Commodity Contracts

The Company uses contracts-for-differences for risk management purposes. Such contracts are matched to an underlying commodity sale or purchase to fix the price and are used solely to reduce risk. The settled amounts under these contracts are recorded as adjustments to revenues or energy purchases in the period settled. For any financial contracts that were considered part of a macro-hedge in 2003 but cannot meet the hedge effectiveness tests of the new Hedging guideline, fair value accounting will apply – see Future Accounting Changes.

Amounts in Lieu Income Taxes

The Company accounts for amounts in lieu of income taxes in the same manner as federally and provincially legislated income taxes on the basis that amounts are a form of income taxes and their determination is exactly the same as income taxes.

Critical Accounting Estimates

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the items for which significant estimates were made in the financial statements:

Electricity Revenues, Costs and Unbilled Consumption

Due to the imprecision in customer consumption data received from load settlement agents, the lag between billing dates and meter reading dates and the lag between billing dates and financial reporting dates, the Company must use estimates for determining the amount of energy consumed but not yet billed. These estimates affect accrued revenues, accrued energy costs and unbilled consumption of the Energy Services segment. There are a number of variables in the computation of these estimates, and the underlying energy settlement processes within the Company and the Alberta and Ontario electric systems are complex. Owing to known challenges within the Alberta and Ontario electric systems, the statutory delays in final load settlement determinations and information and internal billing issues, adjustments to previous estimates could be material.

Fair Values

For determining potential asset impairments and certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value are mainly based on discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

Allowance for Doubtful Accounts

The Company continually reviews its aged accounts receivable and assesses the underlying credit quality of the customers or counterparties. The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors including the aging of receivables, historical write-offs within customer groups, assessments of the collectibility of amounts from individual customers and general economic conditions. As the assessment of allowances is an estimate, actual bad debt experience will vary from the estimate.

Useful Lives of Assets

Depreciation and amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Depreciation and amortization also includes amounts for future decommissioning costs and commencing, in 2004, asset retirement obligation accretion expenses. Estimating the appropriate useful lives of assets requires significant judgement and is generally based on estimates of common life characteristics of common assets.

Income Taxes and Amounts in Lieu of Income Taxes

The Company follows the asset and liability method of accounting for income taxes and amounts in lieu of income taxes. Income taxes and amounts in lieu of income taxes are determined based upon estimates of the Company's current income taxes and estimates of future income taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent that recovery is not considered likely, a valuation allowance will be recorded and charged against income in the period that the allowance is created or revised. Judgemental estimates of the provision for income taxes and amounts in lieu of income taxes, future income tax assets and liabilities and any related valuation allowance might vary from actual amounts incurred.

Future Accounting Standards

Beginning in 2004, the Company has adopted the new accounting standards for impairment of long-lived assets, asset retirement obligations and hedging relationships. These new standards will require a greater use of estimates by management than the previous accounting standards for these items.

Contractual Obligations

$ millions	Payments due by period					
	2004	2005	2006	2007	2008 and thereafter	Total
Long-term debt	$ 55.6	$ 131.0	$ 169.4	$ 46.5	$ 1,298.1	$ 1,700.6
Acquired PPA obligations[1]	245.1	223.8	200.2	203.8	561.0	1,433.9
Other purchase obligations	53.8	14.2	11.6	9.4	4.5	93.5
Capital investments	51.8	–	–	–	–	51.8
Operating leases	1.6	2.0	2.0	1.8	7.0	14.4
Total contractual obligations	$ 407.9	$ 371.0	$ 383.2	$ 261.5	$ 1,870.6	$ 3,294.2

1 The Company's obligation to make payments on a monthly basis for fixed and variable costs under the terms of its acquired PPAs will vary depending on generation volume and scheduled plant outages.

In the normal course of business, the Company provides financial support and performance assurances including guarantees, letters of credit and surety bonds to third parties in respect of its subsidiaries. The liabilities associated with these underlying subsidiary obligations are included in the consolidated balance sheet. The Company has agreed to indemnify certain liabilities of UE Waterheater Income Fund primarily consisting of potential tax and other liabilities that could arise relating to operations of the water heater rental business prior to the sale to the Fund. Any known liabilities associated with this indemnification have been recorded at December 31, 2003 and it is uncertain what, if any, additional amounts may be incurred in the future. There were no other material guarantee obligations outstanding in respect of third parties at December 31, 2003.

Related Party Transactions

The Company enters into various transactions with its sole shareholder, the City of Edmonton. These transactions are in the normal course of operations and are recorded at the exchange value generally based on normal commercial rates or as agreed to by the parties.

The Company recorded interest expense of $76.7 million in 2003 compared to $82.1 million in 2002 on its debt obligation to the City of Edmonton. This debt obligation relates to debt capital raised by the City of Edmonton prior to 1996 when EPCOR commenced raising capital directly. The decrease in interest expense corresponds to the decrease in the obligation. The outstanding balance of the obligation to the City of Edmonton was $540.4 million at December 31, 2003, a decrease of $86.6 million from the amount outstanding at the end of the previous year.

Sales from the Company to the City of Edmonton included electricity and maintenance, repair and construction services totalling $48.7 million in 2003 compared to $46.3 million in 2002. The Company paid franchise fees to the City, determined on the basis of distribution volumes and water revenues, and property taxes of $40.5 million in 2003 and $39.4 million in 2002. The City provided miscellaneous services to the Company totalling $17.0 million in 2003 and $15.7 million in 2002.

Regulation

The Company is subject to regulatory legislation in Alberta, Ontario and the State of Washington including the regulations and codes issued thereunder. The following are the key regulatory issues that had an impact on 2003 results including an assessment of the future impact:

Electricity Pricing, Conservation and Supply Act, 2002

On December 9, 2002, subsequent to the market opening of electricity deregulation in Ontario, the Ontario Legislative Assembly enacted the *Electricity Pricing, Conservation and Supply Act, 2002,* (the Act). Among other things, the Act imposed a maximum retail price cap of 4.3 cents for one-kilowatt-hour of electricity payable by low-volume consumers or designated consumers. Contracts entered into by the Company with Ontario customers in 2002, in addition to those purchased from Ontario Hydro Energy in 2002, have prices in excess of the 4.3 cent cap. Retail contracts in effect at the time the Act came into force have been honoured at the electricity price inherent in the contract, meaning that the Company will continue to earn revenues at the contracted price, with the consumer funded by the province for the difference between the contract price and the price cap.

In November 2003, the *Ontario Energy Board Amendment Act* announced the introduction of tiered electricity pricing for those customers receiving the legislated price cap. Effective April 1, 2004, low volume and designated customers will pay 4.7 cents per kilowatt-hour of electricity for the first 750 kilowatt-hours consumed in any month with any excess of the actual consumption over that threshold being priced at 5.5 cents per kilowatt-hour. This tiered pricing structure is a transition measure until the Ontario Energy Board develops a new pricing structure expected to be in place by May 1, 2005. The regulation is not expected to have a significant impact on the Company's Ontario operations.

Changes to the *Electric Utilities Act* (Alberta)

Effective June 1, 2003, a new *Electric Utilities Act* in Alberta was passed requiring AEUB regulation of municipal RRT and distribution tariffs of certain municipally owned utilities effective January 1, 2004, including those of Energy Services and Distribution, respectively; and mandated a flow through regulated rate service offering after the expiry of the existing RRT transition periods for commercial customers at the end of 2003, and residential and farm customers at the end of 2005. In November 2003, the Government of Alberta announced the extension of the regulated rates for residential and farm customers and for small and medium commercial customers to July 1, 2006.

Risk Management

Electricity Price Risk

The Company buys and sells electricity in the wholesale markets of Alberta, Ontario, the U.S. Pacific Northwest and several states in the eastern United States. Such exchanges are settled at the hourly spot market prices of the respective markets. The Company currently uses purchase and sale arrangements including contracts-for-differences and firm price physical contracts for periods of varying duration to manage the Company's exposure to spot price variability and maintain the Company's exposure within the specified risk limits. Due to the reduced market liquidity (limited product availability and reduced number of creditworthy parties) and the varying shape of electricity consumption during peak usage hours compared with off-peak usage hours, it is not possible to perfectly hedge all positions every hour. The Company does however balance its electricity book within the limits of its policies, which recognize the limitations of the market. The Company generally trades in electricity to reduce its exposure to changes in electricity prices or to match physical or financial obligations.

When aggregate customer electricity consumption (load shape) changes unexpectedly, the Company is exposed to price risk. Load shape refers to the different pattern of consumption between peak hours and off-peak hours. Consumption is highest during peak hours, which are generally the waking hours of the day. Conversely, consumption is lower during off-peak hours. The Company purchases blocks of electricity in advance of consumption in order to minimize exposure to extreme price fluctuations especially during higher priced, peak hour periods. In order to do this, the Company relies upon historical aggregate consumption data (load shape) provided by load settlement agents and local distribution companies to anticipate what aggregate customer consumption will be during peak hours. When consumption varies from historical consumption patterns and the volume of electricity purchased for any given peak hour period, the Company is exposed to the prevailing market prices to either buy the electricity if it is short or sell the electricity if it is long. Exposures can be exacerbated by system events like an unexpected generation plant outage and unusual weather patterns.

The Company holds the PPA related to ATCO's Battle River power plant which entitles it to approximately 398 megawatts of generation capacity of the Battle River power plant located in central Alberta. The generation from the plant comprises part of the Company's long-term electricity supply. In 2003, due to weather conditions causing drought, the water level in the plant's cooling pond was at an historical low. However, the water level has since increased to higher levels. The cooling pond is used for the plant's production of electricity. At low water levels operation of the plant may be affected. Under the terms of the PPA, EPCOR is entitled to the value of the replacement power unless the reduction of output can be shown to be caused by a force majeure event. Should a force majeure event occur, the Company would be required to procure the replacement electricity that it is short of, at rates prevailing at that time. Given the lack of market liquidity, the prices could be significantly higher than the prices inherent in the Battle River PPA, thus increasing the cost of energy purchases to the Company. The Company continuously monitors the Battle River situation closely and has implemented risk mitigation actions that will assist in protecting the Company in the event that the plant suffers a reduction in generation or suffers a prolonged outage. Not withstanding these risk mitigation measures, the Company could still be faced with price exposure if the plant generation is curtailed.

Electricity sales associated with the Company's generating plants that are subject to PPAs are governed by the terms of the PPAs. These sales are accounted for as long-term, fixed margin contracts, which effectively limit any affect on these operations from varying electricity prices, unless plant production drops significantly below the PPA committed capacity for an extended period.

Natural Gas Price Risk

Price risk associated with natural gas purchased for the Company's natural gas-fired generating stations operating under PPAs is mitigated by the provisions of the PPA which require the PPA holder to pay the generator a market indexed price or buy the gas outright on behalf of the plant. Natural gas price risk associated with the Joffre cogeneration plant is partially flowed through to the underlying electricity sale price. At the Frederickson plant, 50 per cent of the gas supply is provided by the customers under tolling agreements.

For its retail natural gas business, the Company balances its exposure by purchasing gas back to back with its sales contracts to the fullest extent possible. That is, the Company normally only purchases in advance, enough physical gas delivery to satisfy the natural gas load represented by expected volumes from signed contracts, with a small capacity for gas storage. Natural gas exposures are managed to the specific limits established by the Company's risk management policies.

The initial term of a block of natural gas contracts that the Company acquired in 2000 expires late in 2004. The customers under these contracts have an option to renew at the original contracted price which the Company will execute upon receiving written request from the customer. Due to the relatively low embedded price, the Company will likely experience losses on servicing these contracts if they renew. The amount of loss is uncertain but the Company's exposure is estimated to range up to $20.0 million over the next five years depending on future natural gas purchase prices and the number of customers who renew their contracts.

Coal Price Risk

The Company's fuel expense is predominantly comprised of coal supply for the Company's Genesee 1 and Genesee 2 plants. Coal is supplied under long-term agreements with the Genesee Coal Mine joint venture, of which the Company holds a 50 per cent interest. When Genesee Phase 3 is completed, it will also obtain its coal from the Genesee Coal mine using pricing arrangements that are similar to those for Genesee 1 and Genesee 2. The price of coal is based on a cost of service model and is therefore not subject to market price volatility.

Credit Risk

Credit risk is associated with the ability of counterparties to various contract arrangements to satisfy their contractual obligations to the Company, including payment and performance. Credit risk is managed by making appropriate credit assessments of counterparties, dealing with creditworthy counterparties and where appropriate, requiring the counterparty to provide appropriate security. Credit exposures and practices are governed by specific credit limits set out in the Company's credit policy. During 2002 and 2003, there was a general reduction in the number of creditworthy counterparties in the wholesale electricity marketplace. This makes management of risk more difficult for the Company as it reduces market liquidity and could impede the Company's ability to quickly and cost effectively react to changes in electricity long or short positions. It is anticipated that liquidity in the markets in which the Company operates will slowly improve over time as more creditworthy counterparties emerge in the marketplace.

Operational Risk

The Company's plant operations are susceptible to outages due to equipment failure, which could make plants unavailable to provide service. This is also true for the generating units associated with the acquired PPAs. Such risks are partially mitigated by the Company's and the PPA holders' operating and maintenance practices that minimize the likelihood of prolonged unplanned down time. The Company has a very strong record of availability, as measured against its peers by the Canadian Electricity Association. In addition, the penalty provisions within the PPAs provide appropriate incentives to owners to keep the plants operational. The terms of the PPA also provide force majeure protection for high-impact, low probability events concerning major equipment failures. The Company's maintenance practices are augmented by the maintenance of strategic spare parts, which can reduce down time considerably in the event of failure. Finally, the Company has secured appropriate business interruption insurance to reduce the impact of prolonged outages at Genesee, Sundance, Battle River and Frederickson caused by insured events.

Operational risk in Distribution and Transmission and Water Services is managed through sound maintenance and safety practices and rigorous quality control testing of water purification.

Environmental Risk

The Company complies, in all material respects, with federal, provincial and local environmental legislation and guidelines with respect to its electricity and water operations. As the Company's generation business is a significant emitter of carbon dioxide, a greenhouse gas, it must comply with emerging federal and provincial requirements including a program to offset emissions. The greenhouse gas reduction targets embedded in the Kyoto protocol could result in increased future costs to the Company, depending on how the targets and associated remediation costs are ultimately allocated to industry sectors, emitters and consumers. Water quality risks in the Company's service area are controlled through stringent water treatment standards and controls. The Company continues to work with governments of all levels to ensure that the legislated targets can be met.

The Company participates in the Clean Air Strategic Alliance which has recommended a framework on sulphur dioxide, nitrogen oxide, mercury and particulate emissions to the Alberta government for both natural gas- and coal-fired generation plants. It has also recommended that mercury emission standards be implemented for coal-fired generation plants. At this point in time, there is no legislated obligation that the Company is required to assume for capital costs to fulfill potential mercury control requirements.

Weather Risk

Weather can have a significant impact on the Company's operations. Temperature levels, seasonality and precipitation, both within the Company's markets and adjacent geographies, can affect the level of demand for electricity and natural gas, thus resulting in electricity and natural gas price volatility. In addition, the level of precipitation affects the availability of the Company's hydro-generating units and also impacts the cooling pond reservoir level at the Battle River generation plant and therefore can impact the performance of the Battle River PPA. The level and quality of spring run-off in the North Saskatchewan River affects the quality of water entering the Company's water purification systems and the resulting costs of purification. Seasonal weather patterns are a factor in the volume and extent of water main breaks. Weather levels and seasonality also impact the demand for and supply of water.

Weather related financial instruments are available in the financial markets but the Company has not pursued them due to their limited coverage and relatively high cost.

Government and Regulatory Risk

Under the Settlement System Code of the *Electric Utilities Act* (Alberta), a retailer must rely upon load settlement agents to provide customer consumption data to be used by retailers in computing their customers' bills. Both the Company and certain load settlement agents have experienced challenges since 2001 to provide quality customer consumption data for timely and accurate billings to customers. Although the Company began working with load settlement agents early in 2002 to resolve issues related to settlement and the accuracy of customer consumption data, adjustments to bills continued throughout 2003, albeit at a reduced frequency by year-end. Under an amendment to the Regulated Default Supply Regulation which came into effect in June 2003, regulated rate providers may not collect an amount undercharged due to a billing error if the error occurred more than twelve months before the date of the revised billing. As part of the Company's ongoing efforts to improve billing and resolve unbilled revenue issues, in 2003, the Company wrote-off $19.0 million representing the estimated amount of unbilled revenue that could not be billed to customers as a result of the billing limitation period prescribed in the legislation.

The Company has reached a negotiated settlement with RRT customers with respect to energy procurement for the 2004 RRT and received interim regulatory approval for its 2004 RRT rates.

Foreign Exchange Risk

The Company's Frederickson plant, located in the State of Washington, is accounted for as a self-sustaining foreign operation utilizing the current-rate method of foreign currency translation. The Company manages its exposure to foreign exchange risk on these operations by offsetting its investment with a U.S. dollar denominated loan. The net impact of the unrealized gains or losses of the investment and the offsetting loan are accumulated and reported as "foreign currency translation adjustment" in shareholder's equity. Since the offsetting financing was not put into place until the end of the first quarter, the accumulated foreign currency translation adjustment reflects an unrealized exchange loss incurred in the first quarter. Approximately one-half of this foreign exchange loss will be realized on the anticipated sale of a 49.85 per cent interest in the Frederickson plant – see following Outlook section.

In situations when the Company contracts to purchase larger value parts for generation, distribution and transmission operations from suppliers outside of Canada, the Company generally fixes the purchase price in Canadian dollars by contracting in Canadian dollars or through the use of forward exchange contracts. The Company may also use forward exchange contracts to fix U.S. denominated financing obligations. There were no such forward exchange contracts in place at the end of 2003.

Income Taxes

The Company is currently undergoing its first income tax audit by the Canada Customs and Revenue Agency, which is expected to last until the last quarter of 2004. The results of the audit or the impact of adjustments, if any, cannot be estimated.

Off-balance Sheet Arrangements

The Company uses various derivative financial instruments including contracts-for-differences to manage its exposure to electricity and natural gas price risk. These contracts-for-differences are not recorded on the balance sheet since they are designated as hedges, and gains and losses relating to the contracts are deferred and recognized in the same period and financial statement category as the corresponding hedged transaction. At December 31, 2003, the fair value of these contracts was estimated to be $42.8 million (2002 – $160.1 million) which represents the net amounts that would have been received on the termination of the contracts with the counterparties at that date.

The Company does not have any other material off-balance sheet arrangements.

Outlook

The Company has slowed its pace of growth over the last two years and continues to concentrate on operational excellence. Through its integrated structure, the Company expects to optimize the return on its investments in regulated and commercial businesses by strengthening its balance sheet, reducing its risks, paying down its debt and improving productivity while increasing customer satisfaction and employee engagement.

Electricity markets have experienced a general slowdown over the past two years. Deregulation has slowed in most markets in North America. There is currently an overbuild of generation in Alberta and the Pacific Northwest while demand catches up to supply. Relatively high natural gas prices and low electricity prices have compressed the "spark spread" on natural gas fired generation plants reducing the periods of time in which they are economical to operate. Wholesale electricity prices are expected to be lower in 2004 than 2003 levels in Alberta, Ontario and the Pacific Northwest.

The Company expects further improvements in 2004 in the Alberta settlement process, which should result in improved billing completeness and timeliness. It is not expected that the proposed sale of Aquila Networks Canada (the wire service provider in EPCOR's RRT area of Energy Services outside of the city of Edmonton) to Fortis Inc. will have a material impact on this expectation.

The Company's key performance drivers include maintaining favourable regulation and good operational performance in the development and operation of generating plants and water treatment facilities, as well as maintaining good customer relations through the delivery of value added products and services.

The construction of Genesee Phase 3 will continue to be a major focus for management in 2004. Capital expenditures, excluding business acquisitions or disposals, in 2004 are projected to remain stable and in the range of those incurred in 2003. Cash flow from operating activities will remain strong although it is not expected to match the level achieved in 2003 as the deferral accounts were substantially collected by the end of 2003. Income from continuing operations is expected to increase from that achieved in 2003 as bad debts expense and revenue and energy purchase adjustments related to billing issues are expected to decline.

Summary of Quarterly Revenues and Net Income

Quarter ended	Revenues (as restated)	Income from continuing operations	Income (loss) from discontinued operations	Net income
(Unaudited, in millions)				
December 31, 2003	$ 603.5	29.6	279.7	$ 309.3
September 30, 2003	670.0	36.9	2.7	39.6
June 30, 2003	597.2	25.1	0.7	25.8
March 31, 2003	718.3	63.1	0.5	63.6
December 31, 2002	665.0	25.1	0.3	25.4
September 30, 2002	649.0	60.9	1.2	62.1
June 30, 2002	604.1	50.1	0.9	51.0
March 31, 2002	594.1	48.8	(2.9)	45.9

Revenues for the seven quarters prior to the last quarter of 2003 have been restated and will be less than the revenues reported in previous 2003 interim reports and the 2002 annual report. In particular, revenues from discontinued operations have been deducted from previously reported revenues. Reported revenues above reflect revenues from continuing operations. Revenues and expenses from discontinued operations, on a net basis, have been reclassified to income from discontinued operations.

Additional Information

Additional information relating to EPCOR including the Company's Annual Information Form (AIF) is available on SEDAR at www.sedar.com

The accompanying consolidated financial statements of EPCOR Utilities Inc. are the responsibility of management and have been approved by the Board of Directors. In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with Canadian generally accepted accounting principles. The preparation of financial statements necessarily requires judgement and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgement where estimates were required, and these consolidated financial statements reflect all information available to March 10, 2004. Financial information presented elsewhere in this annual report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board of Directors.

The consolidated financial statements have been examined by KPMG LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles. The auditors' report outlines the scope of their audit examination and states their opinion.

The Board of Directors, through the Audit Committee, is responsible for ensuring management fulfils its responsibility for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and recommends their approval to the Board of Directors. The external auditors have full and open access to the Audit Committee, with and without the presence of management.

On behalf of management,

Donald J. Lowry
President and Chief Executive Officer

Mark D. Wiltzen
Senior Vice President and
Chief Financial Officer

March 10, 2004

AUDITORS' REPORT TO THE SHAREHOLDER OF EPCOR UTILITIES INC.

We have audited the consolidated balance sheets of EPCOR Utilities Inc. as at December 31, 2003 and 2002 and the consolidated statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of EPCOR Utilities Inc. as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Edmonton, Canada

March 10, 2004

Consolidated Statements of Income (in millions of dollars)
Years ended December 31, 2003 and 2002

	2003	2002
Revenues:		
Energy sales	$ 2,397.4	$ 2,336.2
Other operating revenues	191.6	176.0
	2,589.0	2,512.2
Operating expenses:		
Energy purchases	1,568.4	1,476.8
Fuel	38.7	40.7
Operations, maintenance and administration	415.9	396.9
Franchise fee, property taxes and other taxes	48.0	46.3
Depreciation, decommissioning and amortization (note 5)	169.3	156.9
	2,240.3	2,117.6
Operating income before financing expenses	348.7	394.6
Financing expenses (note 17)	117.5	121.9
Income from continuing operations before income taxes and amounts in lieu of income taxes	231.2	272.7
Income taxes and amounts in lieu of income taxes (note 18)	55.5	75.7
Income from continuing operations before preferred share dividends	175.7	197.0
Preferred share dividends paid by subsidiary companies	21.0	12.1
Net income from continuing operations	154.7	184.9
Discontinued operations (note 2):		
Net loss from operations	(7.5)	(0.5)
Gain on sale	291.1	–
	283.6	(0.5)
Net income	$ 438.3	$ 184.4

See accompanying notes to consolidated financial statements.

Consolidated Statements of Retained Earnings (in millions of dollars)
Years ended December 31, 2003 and 2002

	2003	2002
Retained earnings, beginning of year	$ 1,296.0	$ 1,212.1
Net income	438.3	184.4
Common share dividends paid	(110.5)	(100.5)
Retained earnings, end of year	$ 1,623.8	$ 1,296.0

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheets (in millions of dollars)
December 31, 2003 and 2002

	2003	2002
Assets		
Current assets:		
Cash and cash equivalents	$ 414.5	$ 14.6
Investment in UE Waterheater Income Fund (note 2)	51.3	–
Accounts receivable (note 3)	473.0	607.7
Other current receivables	23.7	200.3
Income taxes recoverable	22.7	–
Inventories	32.5	37.0
Prepaid expenses	9.7	22.0
Future income tax asset (note 18)	0.1	2.2
Current assets of discontinued operations (note 2)	4.0	65.5
	1,031.5	949.3
Deferred amounts receivable (note 4)	–	28.1
Property, plant and equipment (note 5)	2,802.4	2,905.2
Power purchase arrangements (note 6)	185.8	205.8
Customer base and service rights (note 7)	72.6	96.7
Future income tax asset (note 18)	218.6	184.2
Other assets (note 8)	37.1	27.6
Non-current assets of discontinued operations (note 2)	0.3	328.6
	$ 4,348.3	$ 4,725.5

Approved on behalf of the Board:

Hugh J. Bolton
Director and Chairman of the Board

Mary C. Arnold
Director and Chair of the Audit Committee

	2003	2002
Liabilities and Shareholder's Equity		
Current liabilities:		
Short-term debt (note 9)	$ 116.7	$ 182.4
Accounts payable and accrued liabilities	324.2	370.6
Income taxes and amounts in lieu of income taxes payable	–	48.8
Deferred utility obligation (note 10)	24.8	180.4
Other current liabilities	9.0	9.8
Future income tax liability (note 18)	42.4	54.7
Current portion of long-term debt (note 11)	55.6	66.1
Current liabilities of discontinued operations (note 2)	1.5	34.3
	574.2	947.1
Long-term debt (note 11)	1,645.0	1,839.3
Other non-current liabilities (note 12)	150.9	129.3
Future income tax liability (note 18)	24.9	10.2
Deferred utility obligation (note 10)	–	26.7
Non-current liabilities of discontinued operations (note 2)	–	124.9
	2,395.0	3,077.5
Preferred shares issued by subsidiary companies (note 13)	345.7	346.0
Shareholder's equity:		
Share capital (note 14)		
Retained earnings	1,623.8	1,296.0
Foreign currency translation adjustment (note 15)	(16.2)	6.0
	1,607.6	1,302.0
Subsequent event (note 2)		
Contingencies and commitments (note 23)		
	$ 4,348.3	$ 4,725.5

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows (in millions of dollars)
Years ended December 31, 2003 and 2002

	2003	2002
Operating activities:		
Net income	$ 438.3	$ 184.4
Items not affecting cash:		
Depreciation, decommissioning and amortization (note 5)	191.2	181.2
Gain on sale of water heater rental business (note 2)	(291.1)	–
Other non-cash items	4.4	55.4
Future income taxes and amounts in lieu of income taxes	(19.7)	(21.5)
	323.1	399.5
Decrease in deferred amounts receivable	191.8	181.1
Change in other non-current items	(18.0)	(15.0)
Change in non-cash operating working capital (note 16)	60.8	(28.1)
	557.7	537.5
Investing activities:		
Property, plant and equipment and other assets	(251.8)	(480.5)
Proceeds on disposal of water heater rental business (note 2)	735.5	–
Advances to water heater rental business	(267.0)	–
Proceeds on disposal of plant under construction (note 26)	156.9	–
Proceeds on disposal of turbine rights	–	14.1
Proceeds on disposal of other assets	1.9	–
Business acquisitions (note 26)	–	(231.5)
	375.5	(697.9)
Financing activities:		
Net (decrease) increase in deferred utility obligation	(182.3)	207.1
Principal payments on long-term debt	(91.5)	(96.6)
Re-purchase of medium-term notes (note 11)	(221.0)	–
Debenture borrowings	–	300.0
Decrease in notes payable	(182.4)	(314.2)
U.S. financing, short-term debt	128.5	–
U.S. financing, long-term debt	126.0	–
Preferred shares issued by subsidiary (net of issue costs)	(0.1)	193.4
Common share dividends paid	(110.5)	(100.5)
	(533.3)	189.2
Net increase in cash and cash equivalents	399.9	28.8
Cash and cash equivalents (bank indebtedness), beginning of year	14.6	(14.2)
Cash and cash equivalents, end of year	$ 414.5	$ 14.6

See accompanying notes to consolidated financial statements.

1. Summary of Significant Accounting Policies

(a) Financial Statement Presentation:

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles.

The common shares of EPCOR Utilities Inc. (the Company or EPCOR) are owned by the City of Edmonton. The Company was established by City Council under City By-law 11071.

These consolidated financial statements include the accounts of the Company and its subsidiaries, EPCOR Generation Inc., EPCOR Distribution Inc., EPCOR Transmission Inc., EPCOR Energy Services Inc., EPCOR Energy Services (Alberta) Inc., EPCOR Water Services Inc., EPCOR Technologies Inc., EPCOR Power Development Corporation, EPCOR Power Holdings Corporation, EPCOR PPA Management Inc., EMCC Limited, EPCOR Finance Corporation, EPCOR Preferred Equity Inc., EPCOR Credit Inc., 812244 Alberta Ltd., 4202643 Canada Inc., and EPCOR Capital Inc.

These consolidated statements include the results of the water heater rental business previously carried on through the Company's former subsidiaries, Union Energy Inc. and EPCOR Energy Securitizations Inc. until the sale of these operations to an income fund effective December 18, 2003, as described in note 2. The water heater rental business has been classified as discontinued operations in the accompanying financial statements and notes to the financial statements for all periods presented.

All significant intercompany balances and transactions have been eliminated on consolidation.

(b) Nature of Operations:

The Company provides regulated and non-regulated electric utility services, natural gas services, water utility services, and complementary commercial services.

(c) Regulation:

EPCOR's electric transmission operations are regulated by the Alberta Energy and Utilities Board (AEUB). EPCOR's electric distribution operations and municipal Regulated Rate Option (RRO) tariffs in the City of Edmonton were regulated by the City of Edmonton Council until December 31, 2003. On January 1, 2004, pursuant to an amendment of the Electric Utilities Act of Alberta (EUA), the electric distribution operations and RRO tariffs became subject to regulation by the AEUB. The RRO service provided by the Company to customers outside of Edmonton continues to be regulated by the AEUB. The AEUB administers acts and regulations regarding tariffs, rates, construction, financing, operations, accounting and service area. The City of Edmonton Council, until the aforementioned regulatory change on January 1, 2004, established the electrical distribution and RRO tariffs to charge customers within the City of Edmonton.

EPCOR's generating plants in Alberta that commenced operations before January 1, 1996, are operated under Power Purchase Arrangements (PPAs), which were developed through a process overseen by the AEUB and accounted for as described in note 1(f).

1. Summary of Significant Accounting Policies (continued):

(c) Regulation (continued):

The EUA governs the exchange of all electric energy through the interconnected electric system in the province of Alberta. The Power Pool of Alberta (Power Pool) is the market through which all physical electricity exchanges and related financial settlements in Alberta are conducted. Generators submit offers to the Power Pool for the supply of energy, and distributors submit demand bids to the Power Pool for their energy requirements. The Power Pool dispatches generators to meet the demand from distributors, and conducts all financial settlements from its market operations. Pursuant to the EUA, operation of the Power Pool as well as administration of the transmission of all electrical energy through the interconnected electric system in the province of Alberta is administered by an independent system operator, the Alberta Electric System Operator (AESO).

EPCOR's water services are regulated by the City of Edmonton Council for water rates to charge customers within the City of Edmonton. The Company determines the water rates to charge other municipalities. Any Alberta municipality served by the Company may apply to the AEUB to resolve disputes in connection with rates, tolls or charges.

(d) Revenue Recognition:

Revenues from the sales of electricity, natural gas or water are recognized upon delivery or availability for delivery under take-or-pay contracts. These revenues include an estimate of the value of electricity, natural gas and water consumed by customers in the year, but billed subsequent to year-end.

Revenue from the sale of goods is recognized when the products have been delivered. Revenue from services is recognized when the service has been performed or delivered.

Revenues from generating plants operating under Power Purchase Arrangements are recognized in accordance with the terms of the arrangements with expected incentives and penalties recorded as described in note 1(f).

Revenues from generating plants developed or acquired by the Company after January 1, 2001, are recognized on the accrual basis at the time of delivery of electricity to the customer.

Revenues from acquired Power Purchase Arrangements are recognized as the electricity is generated and available for delivery.

(e) Cash and Cash Equivalents:

Cash and cash equivalents include cash or highly liquid investments with a maturity at the time of purchase of three months or less and are recorded at cost, which approximates fair market value.

(f) Generating Plants Operating Under Power Purchase Arrangements:

Effective January 1, 2001, in accordance with provincial legislation, generating units owned by the Company began operating under Power Purchase Arrangements (PPAs). PPAs are a form of long-term sales arrangement between the owner of the generating unit and the buyer of the PPA. Under the terms of the PPAs, which range from 3 to 20 years, the Company receives fixed and variable payments designed to cover the forecast costs of operating the generating units, including amounts in lieu of income taxes, as well as a reasonable return. Since the criteria for rate-regulated accounting are no longer met, these plants are accounted for using generally accepted accounting principles for non-rate-regulated operations.

1. Summary of Significant Accounting Policies (continued):

(f) Generating Plants Operating Under Power Purchase Arrangements (continued):

The target levels of generation availability set out in the PPAs recognize that the generating units will experience planned and forced outages over the terms of the PPAs. The Company records the electricity revenue from the generating units under PPAs at the long-term price of power embedded in the PPAs, including expected incentives and penalties for operating above or below specified availability targets set out in the PPA. Under this approach, incentives for the current period are deferred on a plant by plant basis since they are not expected to be sustained over the full term of the PPA. As penalties are incurred, any balance of deferred incentive will be drawn down. If cumulative penalties exceed cumulative incentives for an individual plant, the excess will be charged to income and no deferred charge will be created. Deferred incentive amounts are included in other non-current liabilities in the balance sheet.

(g) Measurement Uncertainty:

The preparation of the Company's financial statements, in accordance with generally accepted accounting principles, requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date.

On January 1, 2001, the Alberta retail electricity marketplace opened to retail competition. The various systems and procedures used by third parties to provide load and settlement data to retailers across the province have been challenged to completely and accurately capture all customer movement, load classification and consumption data. In addition, by regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until eight months after the month in which such electricity was consumed. On May 1, 2002, the Ontario electricity marketplace opened to retail competition. The Ontario market opening created similar issues to those faced in Alberta. The data and the associated processes and systems are complex and are used by the Company to estimate electricity revenues and costs, including unbilled consumption. The Company's estimation procedures will not necessarily detect errors in underlying data provided by industry participants including wire service providers and load settlement agents – see note 23(e).

For determining potential asset impairments and certain disclosures, the Company is required to estimate the fair value of certain assets or obligations. Estimates of fair value are mainly based on discounted cash flow techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate.

The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors including the aging of receivables, historical write-offs within customer groups, assessments of the collectibility of amounts from individual customers and general economic conditions.

Depreciation and amortization, which also includes amounts for future decommissioning costs, is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgement and is generally based on estimates of common life characteristics of common assets.

1. Summary of Significant Accounting Policies (continued):

(g) Measurement Uncertainty (continued):

Income taxes and amounts in lieu of income taxes are determined based upon estimates of the Company's current income taxes and estimates of future income taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent that recovery is not considered likely, a valuation allowance will be recorded and charged against income in the period that the allowance is created or revised.

Certain estimates are necessary since the regulatory environment that the Company operates in often requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions, or other regulatory proceedings.

Adjustments to previous estimates, which will impact net income and could be material, will be recorded in the period they become known.

(h) Inventories:

Inventories held for consumption are valued at the lower of cost and replacement cost. Inventories held for resale are valued at the lower of cost and net realizable value.

(i) Property, Plant and Equipment:

Property, plant and equipment are recorded at cost and include contracted services, materials, interest, direct and indirect labour, overhead costs and net revenues during the pre-operating period. Certain assets may be acquired or constructed with financial assistance in the form of contributions from developers or customers and non-repayable government grants. Contributions received for financing the costs of assets are recorded as a reduction of the related asset cost.

Depreciation and amortization on assets is provided on the straight-line basis over their estimated useful lives. The AEUB approves depreciation rates for regulated transmission assets. No depreciation is provided on construction work in progress.

Decommissioning charges on certain assets are provided based on estimated removal and site restoration costs, net of salvage value. These amounts are recorded as a provision for plant decommissioning in the balance sheet. Upon the retirement of utility assets, the removal and site restoration costs, net of salvage value, are charged to the provision for plant decommissioning. The removal and site restoration costs for generation plants and for the rate-regulated distribution, transmission, and water assets are based on independent studies of plant decommissioning and site restoration commissioned by the Company and, where applicable, as directed by the regulator.

The Company capitalizes interest during construction to provide for the costs of borrowing on construction activities. Interest is applied during construction using the average cost of debt associated with the specific project.

1. Summary of Significant Accounting Policies (continued):

(j) **Power Purchase Arrangements:**

Acquired power purchase arrangements (PPAs) are recorded at cost and are amortized over their terms on a declining balance basis, effective January 1, 2001.

PPAs reflect the price paid by the Company in 2000 for the rights to the committed generating capacity of five regulated Alberta generating units auctioned by the Government of Alberta as part of provincial electricity deregulation. The Company is obligated to make fixed and variable payments to the owners of the underlying generating units over the terms of the PPAs, which range from 13 to 20 years. Such amounts are recorded as operating expenses as incurred.

The Company purchased the PPAs with an equity syndicate under syndication agreements. Under the terms of the agreements, the syndicate members effectively receive their proportionate share of the committed generating capacity in exchange for their proportionate share of the price paid for the PPAs and all payments to the plant owners. The Company's investment in the PPAs, and its revenues and expenses thereunder, are recorded on a proportionate basis, after deducting the equity syndicate's share.

(k) **Customer Base and Service Rights:**

Customer base represents the cost assigned to the customer relationships associated with the Ontario Hydro Energy electricity contracts acquired in April 2002. The costs are amortized on a straight-line basis over 4 years.

Customer service rights represent the costs to acquire the rights to provide electricity or natural gas services to particular customer groups. The costs are amortized on a straight-line basis over terms ranging from 3 to 20 years depending on the expectation of benefit from the underlying customer group.

(l) **Other Assets:**

Debenture discounts, premiums and issue expenses with respect to long-term debt are amortized over the life of the debt.

Investments are recorded at cost. If there is other than a temporary decline in value of the investment, it is written down to recognize the loss.

Contract rights represent the cost incurred by the Company to secure a long-term sales contract for the electricity generated by a plant acquired in 2000. The cost is amortized on a straight-line basis over the term of the contract.

Deferred charges consist primarily of customer promotional rebates which are charged to income on a basis consistent with the term of the underlying customer contracts.

Long-term receivables are comprised of amounts due from customers in excess of one year from the balance sheet date.

Regulatory costs are recovered or amortized as permitted or required by the AEUB.

1. Summary of Significant Accounting Policies (continued):

(m) Investments in Joint Ventures:

The Company and the coal mine operator at the Genesee plant site each have a 50 per cent interest in the Genesee Coal Mine Joint Venture. The joint venture partner operates the coal mine. Under agreements governing this joint venture, all coal mined is to be supplied to the Company's Genesee generating plant.

The Company holds a 40 per cent interest in the Joffre Cogeneration Project, a 50 per cent interest in the Genesee Phase 3 Project, and a 50 per cent interest in the Taylor's Coulee Chute Hydro Project, all located in the province of Alberta.

The investments in joint ventures are accounted for using the proportionate consolidation method. Under this method, the Company records its proportionate share of assets, liabilities, revenue and expenses of the joint ventures.

(n) Impairment of Long-lived Assets and Intangible Assets:

The Company reviews the valuation of long-lived assets and intangible assets subject to amortization on an ongoing basis, taking into account events and circumstances that might indicate impairment in value. Such assets include property, plant and equipment, PPAs, customer base and service rights and certain other assets. Where there has been an impairment in value, the asset is written down to the fair value or net recoverable value of the asset, as appropriate.

(o) Foreign Currency Translation:

Foreign currency transactions are translated to Canadian dollars by applying exchange rates in effect at the transaction date. Monetary assets and liabilities denominated in foreign currencies are converted to Canadian dollars at rates of exchange prevailing at the end of the reporting period. All foreign exchange gains and losses are included in income except those relating to the translation of self-sustaining foreign operations.

Self-sustaining foreign operations are accounted for under the current-rate method. Under this method, assets and liabilities are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Revenues and expenses are translated at average exchange rates prevailing during the period. Resulting unrealized gains or losses are accumulated and reported as "Foreign currency translation adjustment" in shareholder's equity.

(p) Derivative Financial Instruments:

To reduce its exposure to movements in commodity prices (electricity and natural gas), foreign currency exchange rates and interest rate changes, the Company uses various risk management techniques including derivative financial instruments. Derivative instruments may include non-exchange traded forward contracts, fixed for floating swaps, options and commodity contracts settled with physical delivery. Such instruments may be used to establish a fixed price for a commodity (electricity or natural gas), an interest bearing obligation or an obligation denominated in a foreign currency.

The Company uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Company's exposure to fluctuations in electricity and natural gas prices. Under these instruments, the Company agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe. Amounts received or paid under contracts-for-differences are recognized as part of the cost of the underlying commodity.

1. Summary of Significant Accounting Policies (continued):

(p) Derivative Financial Instruments (continued):

The Company uses foreign currency denominated long-term debt to hedge exposure to changes in the carrying values of the Company's net investments in foreign operations which arise from changes in foreign exchange rates. Gains and losses on the principal component of the foreign currency long-term debt are deferred and included in a separate component of shareholder's equity. If a hedge is terminated or ceases to be effective, any exchange gain or loss on the hedge which has been deferred up to that date will continue to be deferred in the separate component of shareholder's equity.

The Company may enter into forward interest rate or swap agreements and option agreements. Amounts received or paid under such contracts are matched to the associated cash flows and recorded as an adjustment to interest expense or income.

The Company also enters into non-financial commodity derivative contracts which require the future delivery of commodities at fixed prices. These contracts are not recognized in the financial statements until they are settled.

To the extent that the Company enters into derivative financial contracts which are not hedges, such contracts are recorded at fair value.

(q) Income Taxes:

The Company and its subsidiaries are municipally owned, and were exempt from income taxes prior to January 1, 1999. Effective January 1, 1999, under the Income Tax Act (Canada), a municipally owned corporation is subject to income tax on its operations if the income from those operations for any relevant period that was earned outside the geographical boundaries of the municipality exceeds 10 per cent of the total income from those operations for that period.

As a result of these and other provisions, certain subsidiaries of the Company are taxable under the Income Tax Act (Canada).

Effective January 1, 2001, pursuant to the Alberta Payment in Lieu of Tax Regulation, the Company is required to pay amounts in lieu of income taxes to the provincial Balancing Pool. Such amounts are levied on income from the Company's generating units that are subject to PPAs as well as income earned on certain retail electricity services, to the extent that such income is not otherwise subject to income taxes under the Income Tax Act (Canada) or the Alberta Corporate Tax Act. Amounts in lieu of income taxes are determined in the same manner as if the subject operations were taxable under the Income Tax Act (Canada) or the Alberta Corporate Tax Act. There were no amounts in lieu of income taxes prior to January 1, 2001.

The Company follows the asset and liability method of accounting for income taxes and amounts in lieu of income taxes. Under this method, current income taxes are recognized for the estimated income taxes payable or recoverable for the current year. Future income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on future tax assets and liabilities is recognized in income in the period that includes the date of enactment or substantive enactment.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

1. Summary of Significant Accounting Policies (continued):

(r) **Employee Future Benefits:**

The employees of the Company are either members of the Local Authorities Pension Plan (LAPP) or other defined contribution or defined benefit plans.

The LAPP is a multi-employer defined benefit pension plan. The Trustee of the plan is the Treasurer of Alberta and the plan is administered by a Board of Trustees. The Company and its employees make contributions to the plan at rates prescribed by the Board of Trustees to cover costs under the plan. Since the plan is a multi-employer plan, it is accounted for as a defined contribution plan. Accordingly, the Company does not recognize its share of any plan surplus or deficit.

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to employees who are not otherwise served by LAPP, including employees of new or acquired operations. The aggregate assets and obligations under these plans are not material.

The Company maintains a long-term incentive plan for certain employees, which is based on appreciation of the Company's value over a specified term. The Company accrues such obligations based on the estimated increase in equity value applied to the rights granted under the plan.

2. Discontinued Operations:

On December 18, 2003, the Company sold its water heater rental business to the UE Waterheater Income Fund (the Fund) through an initial public offering of fund units. Total proceeds of $793.3 million were received, comprised of $742.0 million cash and $51.3 million in units of the Fund, after deducting underwriters' fees. The water heater rental business, which had been operated in the province of Ontario through the Company's wholly-owned subsidiaries, EPCOR Energy Securitizations Inc. and Union Energy Inc., involved the rental of water heaters, the sales and service of heating, ventilation and air-conditioning equipment, and related financing. The Fund also acquired control of WestCap Trust, a trust through which the water heater rental business was primarily financed.

The Company's investment in units of the Fund is carried at the net realizable value of $51.3 million reflecting a unit price of $9.475 per unit. Pursuant to the underwriting agreement associated with offering of Fund units, the underwriters were granted an over-allotment option to purchase up to 5,413,000 units of the Fund at $10 per unit. Pursuant to an agreement with the Company, the Fund agreed, at the Company's option, to purchase the same number of units from the Company as purchased by the underwriters under their over-allotment option, at a price of $9.475 per unit.

Subsequent to year-end, on January 9, 2004, the underwriters exercised their over-allotment option in full and the Company, in turn, exercised its option and the Fund purchased all 5,413,000 units held by the Company for $51.3 million in cash.

The gain on sale from disposal of the water heater rental business of $291.1 million is as follows:

Proceeds from disposal, net of underwriters' fees	$ 793.3
Net investment in discontinued operations	(495.6)
Costs of disposal	(6.6)
Gain on sale	$ 291.1

2. Discontinued Operations (continued):

Several small heating, ventilation, and-air conditioning equipment (HVAC) businesses operated as part of the water heater rental business were excluded from the sale to the Fund. These HVAC businesses had either been sold or were in the process of being sold at the time of the sale of the water heater rental business to the Fund. At December 31, 2003, only one remaining HVAC business was held-for-sale by the Company and its sale is anticipated to close in the second quarter of 2004 with no significant gain or loss resulting from the sale.

The results of operations of the water heater rental business, including the results of the HVAC businesses, have been reported as discontinued operations in the consolidated statements of income. The related assets and liabilities included in the sale of the business, as detailed below, have been reclassified as current and non-current assets and liabilities of discontinued operations in the consolidated balance sheets. The discontinued operations are included in the Energy Services segment.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

2. Discontinued Operations (continued):

	2003	2002
Current assets of discontinued operations		
Accounts receivable, net	$ 2.2	$ 44.8
Inventories and prepaid expenses	1.8	17.1
Future income tax asset	–	3.6
	$ 4.0	$ 65.5
Non-current assets of discontinued operations		
Property, plant and equipment	$ 0.3	$ 100.7
Customer base	–	64.9
Future amounts receivable	–	69.4
Future income tax asset	–	30.7
Goodwill	–	28.8
Finance contracts, interest rate swaps and other	–	34.1
	$ 0.3	$ 328.6
Current liabilities of discontinued operations		
Accounts payable and accrued liabilities	$ 1.4	$ 25.7
Income taxes payable and other current liabilities	0.1	8.6
	$ 1.5	$ 34.3
Non-current liabilities of discontinued operations		
Long-term debt	$ -	$ 0.1
Future income tax liability	-	122.7
Other non-current liabilities	-	2.1
	$ -	$ 124.9

Operating results from discontinued operations, which include an allocation of interest expense directly attributable to the discontinued operations, are as follows:

	2003	2002
Revenues	$ 204.7	$ 236.7
Operating expenses	181.1	213.5
Operating income	23.6	23.2
Financing expenses	17.9	21.6
Income taxes	13.2	2.1
Net loss from discontinued operations	$ (7.5)	$ (0.5)

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

3. Accounts Receivable:

	2003	2002
Accounts receivable	$ 341.3	$ 420.7
Estimated unbilled consumption (notes 1(g) and 23(e))	131.7	187.0
	$ 473.0	$ 607.7

Accounts receivable represents amounts billed and due from customers. Estimated unbilled consumption represents an estimate of the value of customer energy and water consumption not yet billed.

During 2003, the Company reduced its estimated unbilled consumtion and revenues by $30.5 million (2002 – $32.0 million) based on its current assessment of ultimate recoverability. Included in the 2003 reduction is a $12.5 million write-down resulting from Government of Alberta regulations passed in June 2003 which, from that date, effectively prevent the Company from billing for regulated electric energy more than one year after it was consumed.

4. Deferred Amounts Receivable:

	2003	2002
2000 Distribution deferral rider	$ –	$ 45.4
2001 Regulated Rate Option collection shortfall	21.8	168.1
	21.8	213.5
Less: current portion included in other current receivables	21.8	185.4
	$ –	$ 28.1

2000 Distribution Deferral Rider

During 2000, the Company applied to and received approval from the City of Edmonton to implement a rate-rider to recover from customers the increased costs relating to 2000 spot electricity prices. In November 2000, the Government of Alberta enacted a regulation suspending collection of all 2000 deferral riders in Alberta pending a review of certain elements of the deferral riders by the provincial regulator, the AEUB. The review was completed in 2001 and the recommendations of the AEUB were forwarded to the applicable regulatory authority for its consideration. Upon receiving the recommendation of the AEUB, the City of Edmonton approved resumption of collection of the 2000 distribution deferral rider, including carrying costs, over a two-year period commencing in January 2002.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

4. Deferred Amounts Receivable (continued):

2001 Regulated Rate Option Collection Shortfall

In November 2000, the Government of Alberta imposed an $0.11 per kilowatt-hour limit on the amount that could be collected from Regulated Rate Option (RRO) customers for electric energy in 2001.

For RRO service provided by the Company outside of Edmonton (ANC service area), which is regulated by the AEUB, the Company reached a negotiated settlement with RRO customers for energy costs in excess of the $0.11 per kilowatt-hour collection limit for 2001. The AEUB authorized collection of the 2001 RRO collection shortfall charge, including carrying costs, in the ANC service area over a two-year period commencing in January 2002.

For RRO service provided by the Company inside the City of Edmonton, the AEUB reviewed energy costs in excess of the $0.11 per kilowatt-hour collection limit for 2001. The AEUB recommended to the City of Edmonton that it authorize collection of the 2001 RRO collection shortfall charge in the City of Edmonton over a two-year period commencing in January 2002. The City of Edmonton enacted a Bylaw authorizing implementation of the AEUB recommendation on an interim basis commencing in January 2002 and on a final basis when the final recommendation of the AEUB was received. In the third quarter of 2002, the City of Edmonton issued a Compliance Certificate, thereby approving the 2001 Regulated Rate Option collection shortfall balance associated with the City of Edmonton service area.

Substantially all of the 2000 Distribution deferral rider and the 2001 Regulated Rate Option collection shortfall were sold to an unrelated purchaser in 2002 – see note 10.

5. Property, Plant and Equipment:

				2003
	Composite depreciation rates	Cost	Accumulated depreciation	Net book value
Generation plants and equipment	3.6%	$ 2,042.8	$ 554.2	$ 1,488.6
Water treatment and distribution	1.9%	923.3	232.6	690.7
Electricity transmission and distribution	3.0%	800.1	304.8	495.3
Retail systems and equipment	11.1%	94.5	32.9	61.6
Corporate information systems and equipment	14.9%	94.1	48.5	45.6
		3,954.8	1,173.0	2,781.8
Contributions:				
Water treatment and distribution	1.4%	(359.6)	(57.9)	(301.7)
Electricity transmission and distribution	1.8%	(83.5)	(31.3)	(52.2)
		(443.1)	(89.2)	(353.9)
Land	–	75.9	–	75.9
Construction work in progress	–	298.6	–	298.6
		$ 3,886.2	$ 1,083.8	$ 2,802.4

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

5. Property, Plant and Equipment (continued):

				2002
	Composite depreciation rates	Cost	Accumulated depreciation	Net book value
Generation plants and equipment	3.5%	$ 2,022.3	$ 488.7	$ 1,533.6
Water treatment and distribution	1.8%	881.8	223.6	658.2
Electricity transmission and distribution	3.0%	765.2	289.2	476.0
Retail systems and equipment	10.0%	84.6	22.4	62.2
Corporate information systems and equipment	14.8%	99.9	45.3	54.6
		3,853.8	1,069.2	2,784.6
Contributions:				
Water treatment and distribution	1.3%	(341.2)	(53.2)	(288.0)
Electricity transmission and distribution	1.8%	(79.1)	(30.5)	(48.6)
		(420.3)	(83.7)	(336.6)
Land	–	74.3	–	74.3
Construction work in progress	–	382.9	–	382.9
		$ 3,890.7	$ 985.5	$ 2,905.2

	2003	2002
Continuing operations:		
Depreciation on assets in service	$ 134.3	$ 123.0
Decommissioning charges	4.0	3.9
Amortization of contributions	(6.2)	(5.9)
Amortization of PPAs	19.9	20.6
Amortization of customer base and service rights	16.9	14.9
Amortization of other assets	0.4	0.4
	169.3	156.9
Depreciation and amortization – discontinued operations	21.9	24.3
	$ 191.2	$ 181.2

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

5. Property, Plant and Equipment (continued):

Interest capitalized to property, plant and equipment for 2003 is $23.7 million (2002 – $11.9 million).

On October 21, 2003, the Company entered into an agreement for the sale of a 49.85 per cent interest in its Frederickson generation plant to Puget Sound Energy, Inc. The sale is subject to regulatory approvals and is not expected to be finalized until the second quarter of 2004. The agreed purchase price is approximately $107.7 million subject to closing adjustments. An expected loss of approximately $10.1 million after income taxes, comprised of book and foreign exchange losses, will be recognized when the sale is finalized.

6. Power Purchase Arrangements:

	2003	2002
Cost	$ 247.9	$ 247.9
Accumulated amortization	62.1	42.1
	$ 185.8	$ 205.8

7. Customer Base and Service Rights:

	2003	2002
Cost	$ 117.4	$ 124.5
Accumulated amortization	44.8	27.8
	$ 72.6	$ 96.7

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

8. Other Assets:

	2003	2002
Cost		
Debenture issue expenses	$ 23.3	$ 23.3
Investments	8.1	2.5
Contract rights	7.9	7.9
Deferred charges	7.3	3.2
Long-term receivables	4.7	0.1
Regulatory costs	3.1	4.7
	54.4	41.7
Accumulated amortization		
Debenture issue expenses	14.1	12.2
Contract rights	0.9	0.7
Deferred charges	2.3	1.2
	17.3	14.1
	$ 37.1	$ 27.6

9. Short-term Debt:

	2003	2002
Bank lines of credit	$ 116.7	$ –
Notes payable	–	182.4
	$ 116.7	$ 182.4

Bank lines of credit are unsecured, and are available to the Company up to an amount of $850.0 million. Of the total, $200.0 million is committed until August 2004, $300.0 million is committed under a two-year extendable term loan until December 2005 and $300.0 million is committed under a three-year extendable term loan until December 2006. At December 31, 2003, the Company had US $90.0 million (CDN $116.7 million) outstanding under its $200.0 million credit facility. Interest on this loan is floating and calculated at the current LIBOR rate plus 0.30 per cent. At December 31, 2003, the calculated rate was 1.46 per cent. Amounts, if any, borrowed under the two and three year term extendable credit facilities are classified as long-term debt – see note 11.

Notes payable outstanding at December 31, 2002, consists of commercial paper bearing interest at rates ranging from 3.05 per cent to 3.40 per cent. The Company's commercial paper program is authorized to $500.0 million and is backed by the committed bank lines.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

10. Deferred Utility Obligation:

	2003	2002
Current	$ 24.8	$ 180.4
Non-current	–	26.7
	$ 24.8	$ 207.1

In October 2002, as supported by the AEUB, the Company sold the deferred amounts receivable balances associated with the service areas as described in note 4, to an unrelated purchaser for cash proceeds totaling $225.0 million. The cash received was recorded as a deferred utility obligation since the transaction was accounted for as a financing arrangement rather than as a sale. The deferred utility obligation is drawn down as the related deferred amounts receivable are collected.

EPCOR serves as agent for the purchaser in billing and collecting the deferred amounts receivable and remits the amounts thereby collected to the purchaser.

11. Long-term Debt:

	2003	2002
Obligation to the City of Edmonton (note 20):		
Due in 1-5 years at 11.00%[1] (2002 – 11.29%[1])	$ 151.9	$ 135.8
Due in 6-10 years at 10.14%[1] (2002 – 10.47%[1])	275.7	305.7
Due in 11-15 years at 8.75%[1] (2002 – 8.87%[1])	83.0	68.1
Due in 16-20 years at 7.01%[1] (2002 – 8.34%[1])	29.8	115.3
Due in 21-25 years (2002 – 5.75%[1])	–	2.1
	540.4	627.0
Debentures, at 4.60%, due in 2005	79.0	300.0
Debentures, at 6.20%, due in 2008	200.0	200.0
Debentures, at 6.95%, due in 2010	200.0	200.0
Debentures, at 6.60%, due in 2011	200.0	200.0
Debentures, at 6.75%, due in 2016	130.0	130.0
Debentures, at 6.80%, due in 2029	150.0	150.0
Non-recourse financing:		
Brown Lake Project, at 8.7%, due in 2016	9.0	9.4
Joffre Cogeneration Project, at fixed and floating rates, due in 2020	84.6	89.0
Three year extendable credit facility, at floating rates	107.6	–
	1,700.6	1,905.4
Less: current portion	55.6	66.1
	$ 1,645.0	$ 1,839.3

[1] Weighted average coupon rate

11. Long-term Debt (continued):

Obligation to the City of Edmonton

Debentures were issued, on behalf of the Company, pursuant to City of Edmonton By-law authorization. The outstanding debentures are a direct, unconditional obligation of the City of Edmonton. The Company's obligation to the City of Edmonton matches the City's obligation pursuant to the debentures. All of the 8.75 per cent debentures, maturing in the year 2018 and totaling $83.0 million, rank as subordinated debt. In the event of default on other interest obligations, the coupon and sinking fund payments on the subordinated debt may be deferred for a period of up to five years, not exceeding the maturity date. If still in default at the end of five years, all unpaid payments plus accrued interest thereon may be repaid by issuing common shares to the City of Edmonton. Except for the subordinated debt, the obligation to the City of Edmonton will rank at least equal to all future debt that may be issued by the Company.

The Company makes annual payments into The Sinking Fund of the City of Edmonton pertaining to certain debenture issues. These payments constitute effective settlement of the respective debt as the sinking fund accumulates to satisfy the underlying debenture maturity. For any specific sinking fund issue, the payment obligation ceases on maturity of the debt.

Debentures

The Debentures are unsecured and are direct obligations of the Company and, subject to statutory preferred exemptions, rank equally with all other unsecured and unsubordinated indebtedness of the Company. The debentures are redeemable by the Company prior to maturity at the greater of par and a price specified under the terms of the debenture.

During the fourth quarter of 2003, the Company purchased and cancelled $221.0 million of debenture debt maturing in January 2005. The difference between the purchase price and the carrying amount of the debentures at the time of purchase amounted to $4.3 million and was charged to financing expenses – see note 17.

Non-recourse Financing

Joffre Cogeneration Project financing represents the Company's share, through its subsidiary, EPCOR Power Development Corporation, of syndicated loans for the project. $40.0 million of the debt bears a fixed interest rate of 8.59 per cent payable quarterly until September 2020 and $7.6 million bears interest at a fixed rate of 5.06 per cent payable quarterly until December 2004. The remaining debt bears interest at the prevailing bankers' acceptance rate plus a spread of 1.50 (2002 – 1.37) per cent which escalates to 1.875 per cent over the term of the loan. The debt is secured by a charge against project assets which have a carrying value of $116.5 million (2002 – $120.1 million). Brown Lake Project financing is secured by a charge against project assets which have a carrying value of $13.1 million (2002 – $13.6 million).

Two and Three Year Extendable Credit Facility

Unsecured two and three year credit facilities of $300.0 million each, committed to December 2005 and December 2006 respectively, are available to the Company. At December 31, 2003, the Company had US $83.0 million (CDN $107.6 million) outstanding under the three year extendable credit facility. Interest on this loan is floating and calculated at the current LIBOR rate plus 0.45 per cent. At December 31, 2003 the calculated rate was 1.61 per cent.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

11. Long-term Debt (continued):

Principal Repayments

Principal repayments to lenders and payments into The Sinking Fund of the City of Edmonton over the next five years are as follows:

2004	$ 55.6
2005	131.0
2006	169.4
2007	46.5
2008	236.5

12. Other Non-current Liabilities:

	2003	2002
Deferred incentives on generating plants operating under PPAs	$ 82.4	$ 68.0
Provision for decommissioning	57.2	53.2
Employee future benefit liabilities	8.7	4.7
Long-term incentive plan liability	1.1	1.8
Other	1.5	1.6
	$ 150.9	$ 129.3

13. Preferred Shares Issued by Subsidiary Companies:

	2003	2002
Balance, beginning of year	$ 346.0	$ 150.0
Gross cash proceeds	–	200.0
Issue costs, net of future income tax	(0.3)	(4.0)
Balance, end of year	$ 345.7	$ 346.0

13. Preferred Shares Issued by Subsidiary Companies (continued):

During 2003, additional share issue costs of $0.3 million were recorded against the preferred shares.

During 2002, a subsidiary of the Company issued 8 million of cumulative, redeemable First Preferred Shares, Series I with dividends payable on a quarterly basis at the annual rate of $1.375 per share. The dividend rate is fixed for the first five years, after which time the dividend rate is subject to reset each succeeding five-year period thereafter. The rate as reset will be determined by the Company at not less than 80 per cent of the five-year Government of Canada Yield. The shares are redeemable, at $25.00 per share, by the subsidiary company at certain times. The shares may be converted to First Preferred Shares, Series II by the holders but are not retractable by the holders.

During 2001, a subsidiary of the Company issued 6 million of 5.75 per cent cumulative, redeemable First Preferred Shares, Series A. The dividend rate is fixed for the first five years, after which time the dividend rate is subject to reset at either a new mutually agreed fixed rate or, at the option of the holders, a floating rate which varies with the prime interest rate. The shares are redeemable, at $25.00 per share, by the subsidiary company at certain times, but are not retractable by the holders.

14. Share Capital:

Authorized:

Unlimited number of voting common shares without nominal or par value.

Issued:

Three common shares for nominal value to the City of Edmonton.

The Company, under terms of intercompany promissory notes between it and its subsidiaries described in note 13, has covenanted that it will not pay any cash dividends on its common shares at any time that the payment of interest on these notes is deferred.

15. Foreign Currency Translation Adjustment:

An unrealized translation adjustment arose on the translation of foreign currency denominated assets and liabilities of the self-sustaining foreign operation. At the end of the first quarter of 2003, the exposure to the net investment in the self-sustaining foreign operation was hedged by borrowing funds denominated in the same foreign currency of the underlying asset. The unrealized foreign exchange loss of $16.2 million at December 31, 2003 was due to the decrease in the U.S. dollar exchange rate prior to implementing the hedge.

At December 31, 2002, there was an unrealized foreign exchange gain of $6.0 million. The gain was predominantly due to the increase in the U.S. net asset base and the increase in the U.S. dollar exchange rate.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

16. Change in Non-cash Operating Working Capital:

	2003	2002
Accounts receivable	$ 131.3	$ 126.6
Other current receivables	176.6	(8.0)
Income taxes recoverable	(22.7)	–
Inventories	13.6	4.6
Prepaid expenses	12.1	(18.4)
Accounts payable and accrued liabilities	(44.3)	(128.9)
Income taxes and amounts in lieu of income taxes payable	(48.5)	(1.7)
Other current liabilities	6.4	2.7
Changes in non-operating working capital items:		
Business acquisitions (note 26)	–	3.4
Change in current portion of deferred amounts receivable	(163.7)	2.5
Change in current portion of finance contracts	–	(9.4)
Loss on write-down of inventories	–	(1.5)
	$ 60.8	$ (28.1)

17. Financing Expenses:

	2003	2002
Interest on long-term debt	$ 136.7	$ 143.2
Other interest expense (income)	(0.5)	8.7
	136.2	151.9
Premium paid on purchase of medium term notes (note 11)	4.3	–
Amortization of debt issue costs	1.6	1.5
Capitalized interest	(23.7)	(11.9)
Interest recovered on deferred amounts receivable	(0.9)	(19.6)
	$ 117.5	$ 121.9

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

17. Financing Expenses (continued):

Interest paid during the year, excluding capitalized interest, was as follows:

	2003	2002
Interest paid on long-term debt	$ 142.4	$ 127.1
Other interest paid	6.1	10.5
	$ 148.5	$ 137.6

18. Income Taxes and Amounts in Lieu of Income Taxes:

	2003	2002
Income taxes	$ 17.0	$ 30.2
Amounts in lieu of income taxes	38.5	45.5
	$ 55.5	$ 75.7
Comprised of:		
Current income taxes and amounts in lieu of income taxes	90.8	90.6
Future income taxes and amounts in lieu of income taxes	(35.3)	(14.9)
	$ 55.5	$ 75.7

Income taxes and amounts in lieu of income taxes differ from the amounts that would be computed by applying the federal and provincial income tax rates as follows:

	2003	2002
Income from continuing operations before income taxes and amounts in lieu of income taxes	$ 231.2	$ 272.7
Statutory income tax rates	36.6%	39.1%
Income taxes and amounts in lieu of income taxes at statutory rates	84.6	106.6
Increase (decrease) resulting from:		
Income exempt from income taxes at statutory rate	(37.2)	(36.9)
Large Corporations Tax	5.0	4.7
Manufacturing and processing credit	(1.8)	(3.4)
Adjustment to future income tax assets and liabilities for enacted changes in income tax laws and rates	3.8	1.4
Other	1.1	3.3
	$ 55.5	$ 75.7

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

18. Income Taxes and Amounts in Lieu of Income Taxes (continued):

Income taxes and amounts in lieu of income taxes paid in 2003 were $162.5 million (2002 – $100.6 million).

The tax effects of temporary differences that give rise to significant portions of the future income tax asset and future income tax liability are presented below:

	2003	2002
Future income tax asset:		
Cumulative eligible capital	$ 91.3	$ 99.0
Property, plant and equipment – differences in net book value and undepreciated capital cost	19.9	15.5
Incentive income from generating plants operating under PPAs – deferred for accounting purposes	45.7	39.8
Non-capital losses carried forward	54.4	21.2
Power purchase arrangements	8.1	5.7
Reorganization costs	(3.0)	–
Preferred share issue costs	1.8	2.4
Customer base and service rights	1.0	0.7
Other	(0.5)	2.1
	218.7	186.4
Future income tax liability:		
Deferred income from partnership	42.4	50.5
Property, plant and equipment – differences in net book value and undepreciated capital cost	14.1	9.2
Construction work in progress	7.3	–
Prepaid expenses	–	4.2
Other assets	3.1	1.0
Deferred amounts receivable	0.4	–
	67.3	64.9
Net future tax asset	$ 151.4	$ 121.5
Presented in the balance sheet as follows:		
Current assets	$ 0.1	$ 2.2
Non-current assets	218.6	184.2
Current liabilities	(42.4)	(54.7)
Non-current liabilities	(24.9)	(10.2)
	$ 151.4	$ 121.5

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

18. Income Taxes and Amounts in Lieu of Income Taxes (continued):

As noted in note 1(q), effective January 1, 2001 the Company became subject to the Payment in Lieu of Tax Regulation (PILOT regulation) in Alberta requiring it to pay amounts in lieu of income taxes on certain of its operations. Under the PILOT regulation, there was a deemed disposition and reacquisition, at fair value, of the applicable assets subject to the regulation. A future amount in lieu of income tax asset of $156.2 million was created since the fair value of the underlying assets for amounts in lieu of income tax purposes was greater than their net book values. As discussed in note 23(f), the Company is defending its position regarding the valuation of goodwill under the PILOT regulation.

19. Financial Instruments:

Fair Value of Recorded Financial Assets (liabilities)

	2003	2002
Long-term debt	$ (2,011.2)	$ (2,084.5)

The fair value of the Company's long-term debt is based on determining a required yield for the Company's debt as at December 31, 2003 and 2002. The required yield is based on an estimated credit spread for the Company over the yields of long-term Government of Canada bonds that have similar maturities to the Company's debt. The estimated credit spread is based on comparisons to publicly traded debt issues of companies with a similar credit rating as reported publicly by independent financial institutions.

The fair values of all other financial assets and financial liabilities are not materially different from their carrying values.

Fair Value of Off-balance Sheet Contracts for Differences

	2003		2002	
	Notional quantity (millions of megawatt hours)	Fair value asset	Notional quantity (millions of megawatt hours)	Fair value asset
Electricity sales	7.1	$ 23.4	8.6	$ 26.6
Electricity purchases	12.2	19.4	18.4	133.5

The fair value of the Company's contract-for-differences is determined by estimating the amounts that would have to be received from or paid to counterparties to terminate the contracts at December 31, 2003 and 2002.

19. Financial Instruments (continued):

Credit Risk

Accounts receivable consist of amounts due from retail customers including industrial and commercial customers, other retailers and other counterparties. Larger commercial and industrial customer contracts and contracts-for-differences provide for performance assurances including letters of credit according to a pre-agreed basis. For other retail customers which represent a diversified customer base, credit losses are generally low across the sector and the Company provides for an allowance for doubtful accounts to absorb credit losses. The allowance for doubtful accounts is $13.0 million (2002 – $7.5 million).

The Company also has credit exposures to large suppliers of electricity and natural gas. The number of creditworthy counterparties has declined in recent years. The Company mitigates this exposure by dealing with creditworthy counterparties and, where appropriate, taking back appropriate security from the supplier.

Interest Rate Risk

The Company is exposed to changes in interest rates on its short-term and certain long-term obligations maturing in the year. At December 31, 2003 approximately 85 per cent (2002 – 90 per cent) of the Company's debt was at fixed rates.

Foreign Currency Risk

The Company has translation exposure to changes in exchange rates on its assets, liabilities and operations denominated in U.S. dollars due to its investment in a power plant in the United States. To manage this exposure, the Company borrows funds in U.S. dollars in an amount that offsets its net assets denominated in U.S. dollars.

When higher value parts for generation, distribution and transmission operations are purchased outside of Canada, the Company generally fixes the purchases in Canadian dollars through the use of forward exchange contracts. Forward exchange contracts may also be used to fix U.S. denominated financing obligations. The aggregate of forward exchange contracts at December 31, 2003, was $ nil (2002 – $ nil).

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

20. Related Party Balances and Transactions:

The following summarizes the Company's related party balances and transactions with the City of Edmonton. All transactions are in the normal course of operations, and are recorded at the exchange value generally based on normal commercial rates, or as agreed to by the parties.

		2003	2002
Balance Sheet:			
Accounts receivable	(a)	$ 31.0	$ 14.6
Property, plant and equipment	(b)	2.9	1.9
Long-term debt – see note 11		540.4	627.0
Income Statement:			
Energy and water sales		$ 23.2	$ 22.5
Other operating revenues	(c)	25.5	23.8
Operations, maintenance and administration	(d)	17.0	15.7
Franchise fee, property taxes and other taxes	(e)	40.5	39.4
Financing expenses	(f)	76.7	82.1

(a) The accounts receivable balance due from the City of Edmonton at the end of the year includes $18.1 million (2002 – $10.3 million) in respect of the negotiated sharing of the earnings of the City of Edmonton Sinking Fund. During the year, the Company received $ nil (2002 – $28.0 million) of these balances.

(b) Costs of capital construction for water distribution mains and infrastructure programs.

(c) Revenues from the provision of maintenance, repair and construction services.

(d) Includes certain costs of printing services and supplies, mobile equipment services, public works and various other services pursuant to service agreements.

(e) Franchise fee of $31.4 million at 0.374 cents per kilowatt-hour (2002 – 0.371 cents per kilowatt-hour) for EPCOR Distribution Inc. and at 7.2 per cent (2002 – 7.2 per cent) of qualifying revenues of EPCOR Water Services Inc. Property taxes of $9.1 million (2002 – $9.1 million) on property owned within the City of Edmonton municipal boundaries.

(f) Interest expense on the obligation to the City of Edmonton.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

21. Joint Ventures:

A financial summary of the Company's investments in joint ventures as at December 31, 2003 and 2002 on a proportionately consolidated basis, is as follows:

	2003	2002
Current assets	$ 15.5	$ 8.2
Long-term assets	463.3	191.6
Current liabilities	20.8	38.0
Long-term liabilities	83.9	115.1
Revenues	41.7	36.8
Expenses[1]	32.2	16.1
Net income	9.5	20.6
Cash flows from operating activities	13.6	22.6
Cash flows from (used in) investing activities	(101.0)	86.1
Cash flows (used in) from financing activities	86.5	(5.3)

1 Excludes all costs of operating the Genesee Coal Mine Joint Venture, which are recorded as fuel expenses by the Company.

22. Pension Costs:

The required employer contributions for the year to the LAPP and the other pension plans, recorded as pension expense, totaled \$8.8 million (2002 – \$8.9 million), of which \$1.5 million (2002 – \$2.6 million) is reflected in the results of discontinued operations.

23. Contingencies and Commitments:

(a) The Company's commitments to capital investments including the Genesee Phase 3 project are estimated at \$51.8 million at December 31, 2003 (2002 – \$244.2 million).

(b) Minimum operating lease payments for premises are approximately:

2004	$ 1.6
2005	2.0
2006	2.0
2007	1.8
2008	1.8
Thereafter	5.2

23. Contingencies and Commitments (continued):

(c) In 2004, under the terms of the acquired PPAs, the Company is obligated to make monthly payments for fixed and variable costs. The estimated annual total of these payments for 2004 is $245.1 million. The actual amounts for 2004 and future years may vary from estimates depending on generation volume and scheduled outages. It is expected that the annual payments over the terms of the PPAs, as described in note 1(j), will range from $200 million to $280 million, adjusted for inflation, other than in the event of a forced outage.

(d) The Company and its subsidiaries are subject to various legal claims that arise in the normal course of business. Management believes that the aggregate contingent liability of the Company arising from these claims is immaterial and therefore no provision has been made.

(e) As disclosed in note 1(g), settlement processes in the Alberta electricity market may result in adjustments to previously settled loads in future periods. The adjustments will result in changes to previous estimates of electricity revenues and expenses. Any such adjustments, which could be material, will be recorded in the period they become known.

(f) Alberta Revenue, Tax and Revenue Administration (Alberta Revenue), as agent for the Balancing Pool of Alberta, is responsible for assessing the Company's amounts in lieu of income tax returns filed under the PILOT regulation. In July 2003, Alberta Revenue notified the Company that it is their view that the value of goodwill for amounts in lieu of income tax purposes, as determined by the Company at the date that the Company first became subject to the PILOT regulation, is overstated. If the value of the Company's goodwill for PILOT purposes is determined to be less than the amount established by the Company on January 1, 2001, certain deductions for amounts in lieu of income tax purposes would decrease, resulting in additional amounts in lieu of income taxes payable and the future amounts in lieu of income tax asset associated with such deductions being written down as a tax expense. At January 1, 2001, the balance of the future amounts in lieu of income tax asset associated with the goodwill was $112.9 million, based on an estimated fair market value of goodwill of $400 million.

The Company believes that it appropriately measured the value of goodwill subject to the PILOT regulation and will continue to defend its position. No valuation provision has been made against the future amounts in lieu of income tax asset and no provision has been made in the financial statements for additional amounts in lieu of income taxes, if any, which may be determined to be payable.

24. Guarantees:

Effective January 1, 2003, the Company adopted the disclosure requirements as set out in CICA Accounting Guideline 14 – Disclosure of Guarantees.

The Company has issued letters of credit for $29.3 million (2002 – $49.5 million) to meet the credit requirements of energy market participants and to satisfy legislated reclamation requirements.

24. Guarantees (continued):

Under terms of disposal of the water heater rental business – see note 2 – the Company has agreed to indemnify the UE Waterheater Income Fund and/or its subsidiaries for: i) liabilities related to assets sold prior to closing of the sale; ii) net tax liabilities of Union Energy Inc. prior to closing; iii) any large corporation taxes payable by the Fund from closing to December 31, 2007 up to $13 million; and, iv) any future net tax liability relating to WestCap Trust resulting from facts, circumstances and practices in effect on or prior to closing. The indemnity in item iv) expires seven years after closing. Any known liabilities have been reflected in the consolidated balance sheet.

In the normal course of business, the Company provides financial support and performance assurances including guarantees, letters of credit and surety bonds to third parties in respect of its subsidiaries. The liabilities associated with the underlying subsidiary obligations are included in the consolidated balance sheet.

The Company has no other material guarantee obligations outstanding in respect of third parties at December 31, 2003.

25. Segment Disclosures:

The Company operates in the following reportable business segments which follow the organization, management and reporting structure within the Company.

Generation

Generation is involved in the development and operation of rate-regulated and non-rate-regulated electrical generation plants within Alberta, British Columbia and the Pacific Northwest region of the United States.

Distribution and Transmission

Distribution and Transmission is involved in the transmission and distribution of electricity within the City of Edmonton. This segment also provides complementary commercial services including streetlighting and transportation support services.

Energy Services

Energy Services is involved in the procurement, marketing and sale of electricity and natural gas in retail and wholesale markets in Alberta and Ontario, water heater rentals in Ontario and heating, ventilation and air conditioning and related financing in Ontario, Manitoba, Alberta, and British Columbia. As discussed in note 2, the water heater rental business and acquired HVAC businesses were sold during 2003 and are presented as discontinued operations.

Water Services

Water Services is primarily involved in the treatment and distribution of water within the City of Edmonton and other communities.

Corporate

Corporate reflects the costs of the Company's net unallocated corporate office expenses and net financing income earned from intercompany guarantee fees and intercompany interest charges.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

25. Segment Disclosures (continued):

Year ended December 31, 2003	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment eliminations	Consolidated
Revenues – external	$ 441.6	$ 73.3	$ 1,944.9	$ 128.7	$ 0.5	$ –	$ 2,589.0
Intersegment revenues	51.9	149.2	22.6	0.2	–	(223.9)	–
Total revenues	493.5	222.5	1,967.5	128.9	0.5	(223.9)	2,589.0
Depreciation, decommissioning and amortization	73.7	22.1	47.0	12.1	14.4	–	169.3
Other operating expenses	218.0	148.8	1,861.6	75.2	(8.7)	(223.9)	2,071.0
Financing expenses	115.1	16.5	47.6	18.3	(80.0)	–	117.5
Income taxes and amounts in lieu of income taxes	32.8	–	10.7	–	12.0	–	55.5
Total expenses	439.6	187.4	1,966.9	105.6	(62.3)	(223.9)	2,413.3
Income from continuing operations before preferred share dividends	53.9	35.1	0.6	23.3	62.8	–	175.7
Preferred share dividends	–	–	–	–	21.0	–	21.0
Income from continuing operations	53.9	35.1	0.6	23.3	41.8	–	154.7
Net income (loss) from discontinued operations (note 2)	–	–	(7.5)	–	291.1	–	283.6
Net income (loss)	53.9	35.1	(6.9)	23.3	332.9	–	438.3
Total assets	2,116.4	500.9	800.2	414.5	533.1	(16.8)	4,348.3
Capital additions	151.2	39.9	21.1	30.4	9.2	–	251.8

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

25. Segment Disclosures (continued):

Year ended December 31, 2002	Generation	Distribution and Transmission	Energy Services	Water Services	Corporate	Intersegment eliminations	Consolidated
Revenues – external	$ 473.9	$ 86.4	$ 1,821.0	$ 130.3	$ 0.6	–	$ 2,512.2
Intersegment revenues	1.0	138.7	28.2	0.2	–	(168.1)	–
Total revenues	474.9	225.1	1,849.2	130.5	0.6	(168.1)	2,512.2
Depreciation, decommissioning and amortization	66.9	21.2	44.0	11.4	13.4	–	156.9
Other operating expenses	236.5	154.8	1,677.3	71.9	(11.7)	(168.1)	1,960.7
Financing expenses	93.8	14.9	37.7	16.6	(41.1)	–	121.9
Income taxes and amounts in lieu of income taxes	36.0	–	30.6	–	9.1	–	75.7
Total expenses	433.2	190.9	1,789.6	99.9	(30.3)	(168.1)	2,315.2
Income from continuing operations before preferred share dividends	41.7	34.2	59.6	30.6	30.9	–	197.0
Preferred share dividends	–	–	–	–	12.1	–	12.1
Income from continuing operations	41.7	34.2	59.6	30.6	18.8	–	184.9
Net loss from discontinued operations (note 2)	–	–	(0.5)	–	–	–	(0.5)
Net income	41.7	34.2	59.1	30.6	18.8	–	184.4
Total assets	2,255.9	522.4	1,490.2	396.4	143.1	(82.5)	4,725.5
Capital additions	364.1	46.6	39.9	26.2	3.7	–	480.5

Geographic Information

			2003			2002
	Canada	U.S.	Total	Canada	U.S.	Total
Revenues – external	$ 2,477.1	$ 111.9	$ 2,589.0	$ 2,493.0	$ 19.2	$ 2,512.2
Capital assets	2,583.1	219.3	2,802.4	2,624.9	280.3	2,905.2

Intersegment transactions occur in the normal course of operations and are recorded at exchange values which are generally at normal commercial rates. Segments are charged amounts for depreciation on corporate assets that are not allocated to the segments for reporting purposes. All other accounting policies of the segments are the same as those disclosed in note 1.

Notes to Consolidated Financial Statements (Tabular amounts in millions of dollars)

26. Disposals and Acquisitions:

Disposals

On January 13, 2003, the Company completed an agreement with TransAlta Corporation (TransAlta) for TransAlta to acquire a 50 per cent interest in the Company's Genesee Phase 3 project. On January 23, 2003, TransAlta paid $156.9 million in cash for their share of costs incurred to date on the project. The Company's interest in this project is accounted for in accordance with note 1(m).

On October 21, 2003, the Company entered into an agreement for the sale of 49.85 per cent interest in its Frederickson generation plant – see note 5. The sale is subject to regulatory approval and is not expected to be finalized until the second quarter of 2004.

On December 18, 2003, the Company disposed of its water heater rental business – see note 2.

Acquisitions

The Company acquired business assets as summarized below:

	2003	2002
Current assets	$ –	$ 3.4
Property, plant and equipment	–	210.7
Customer base and service rights	–	17.4
Net assets acquired	$ –	$ 231.5

Effective April 30, 2002, the Company purchased water heaters and electricity, natural gas and water heater customer contracts and rental agreements from Ontario Hydro Energy Inc. The aggregate cash purchase price was $54.9 million and was allocated to current assets, property, plant and equipment and customer base and service rights.

In August 2002, the Company purchased 60 per cent of Frederickson Power L.P. (the partnership) from Westcoast Energy Inc. The primary asset of the partnership was a power plant under construction in Washington State. The plant commenced commercial operations on September 3, 2002. The aggregate cash purchase price was $176.6 million and was allocated to property, plant and equipment.

27. Comparative Figures:

Certain of the comparative figures have been reclassified to conform with the current year's presentation.

Photography

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Page 10
Alberta Ballet Dancer Hokuto Kodama
Photo by Marty Sohl

Page 4
Genesee Phase 3 Construction Site
Photo by Roth and Ramberg

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